Final Report

City of Wichita, Kansas
Municipalization Feasibility Study

February 2001

R·W·BECK

February 1, 2001

Mr. Joseph T. Pajor
Natural Resources Director
City Hall, 8th Floor
455 North Main Street
Wichita, KS 67202

Subject: **Municipalization Feasibility Study – Final Report**

Dear Joe:

Enclosed please find 20 copies of our Final Municipalization Feasibility Study. This final report reflects the comments on the Draft Report we received from you and the rest of the Project Team. We appreciate the opportunity to provide this Study to you and the City of Wichita, as well as all of your (and your staff's) efforts on behalf of this project. We look forward to continuing our relationship with the City of Wichita.

Please review and call me directly at (303) 299-5328 with any questions or comments.

Sincerely,

R. W. BECK, INC.

Timothy R. Corrigan
National Director, Client Services

TRC/jao
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The City of Wichita ("City") is currently provided electrical service by Kansas Gas and Electric ("KGE") a wholly-owned subsidiary of Western Resources Incorporated ("WRI") company. WRI was formed in 1992 as the result of a merger between KGE and Kansas Power and Light ("KPL"). KPL is now an operating division of WRI. WRI operates as a single integrated electric utility using generation resources of both KPL and KGE to serve the combined WRI load. Although operated as a single utility, WRI has maintained separate rates for KPL customers and KGE customers. KGE customers pay rates that are 25-28 percent higher than KPL customers, which is referred to the rate disparity within this report.

The City has aggressively pursued a variety of available forums to address this rate disparity, including legal and regulatory actions. To date, those actions have been unsuccessful in eliminating the rate disparity. Because the rate disparity still exists the City commissioned a Municipalization Feasibility Study ("Feasibility Study" or "Study"). The Feasibility Study would examine whether or not municipalization of KGE's facilities within the City, and the establishment of a municipal electric utility, could achieve the desired reduction of electric rates in Wichita.

In order to assess the financial feasibility of a municipalization effort, the City has engaged R.W. Beck, Inc. ("Beck") to conduct this economic, financial and technical Feasibility Study. The enclosed report provides a preliminary review of the methodology and results of Beck's Feasibility Study. This Executive Summary provides an abbreviated description of the approach to this study, a presentation of the study results, and summary of conclusions.

APPROACH

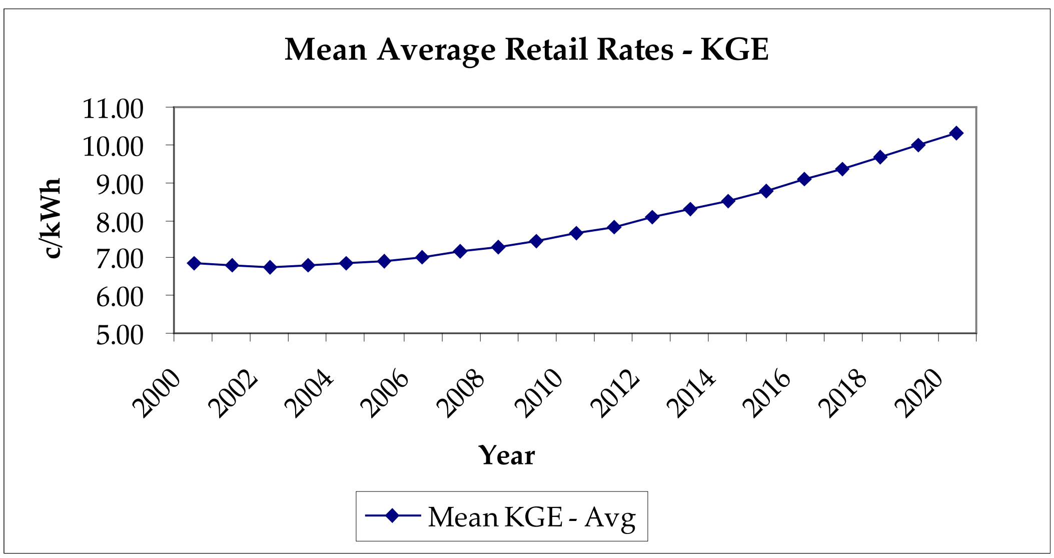
Beck's approach consisted of a review of historical and publicly available information, as well as a field review to assess the general condition of the electric distribution system and to assess the technical issues associated with this effort. Publicly available information primarily consisted of KGE's Federal Energy Regulatory Commission ("FERC") filed reports (Form 1 and others), Energy Information Agency ("EIA") data, Kansas Corporation Commission ("KCC") data, and information from other state, county and City agencies. The field review involved a limited assessment of the type and condition of some of the equipment that comprised the Wichita portions of the KGE system. This field review also provided a limited assessment of the issues and costs associated with severing the electric system inside the City from the remaining KGE system (severance issues). Additionally, Beck provided its insight and expertise as a municipal utility consultant to provide comments on potential municipal operations.

The publicly available information and field review provided Beck with the data necessary to determine the costs to the City associated with continued service by KGE and the costs of operating a municipal utility. These costs were determined by generating a forecast revenue requirement for both KGE and the municipal utility. This revenue requirement was allocated to the ratepayers within KGE's and the City's service areas to determine an average retail rate for each operation.

The forecast of KGE revenue requirement was prepared by an examination of up to 10 years of historical information regarding KGE's loads, expenses, plant additions and other utility cost components. The forecast of revenue requirement approximates one which would have been developed with a traditional regulated cost of service approach, however it is simplified for purposes of developing a 20-year forecast.

The Figure ES-1 below identifies the average KGE retail rate forecasted by Beck over the study period.

Figure ES-1



Source: R. W. Beck

The forecast of municipal utility revenue requirements and rates was developed using assumptions consistent with those used in the KGE forecast. In addition, certain transmission, distribution and administrative costs are consistent with similar KGE costs, although lower, because they are related to operating the same (i.e. former KGE) facilities.

Costs which comprise the municipal utility revenue requirements are the cost of acquisition of KGE facilities, cost to segregate or sever the KGE facilities within the City from the remaining KGE facilities, cost of possible stranded investment, power supply costs and financing costs. Each is summarized briefly below.

ACQUISITION COSTS

Section 2 of this report details the development of the cost of acquisition of KGE facilities within Wichita. Beck estimated the acquisition costs by reasonable allocations and approximations of KGE facilities in the City, supported by a field review by distribution system design professionals. These facilities were then valued for acquisition purposes using Original Cost Less Depreciation and Replacement Cost Less Depreciation methods. Table ES-1 provides the results of this analysis.

Table ES-1
ACQUISITION COST OF KGE TRANSMISSION AND DISTRIBUTION FACILITIES

Item	Amount
Original Cost Less Depreciation	$226,400,000
Replacement Cost Less Depreciation	$323,300,000

SEVERANCE COSTS

As part of the field review of KGE facilities, Beck developed a reasonable estimate for the costs of separating the KGE facilities from the remaining KGE system. Table ES-2 below shows the results of the severance cost estimate.

Table ES-2
SEVERANCE COSTS

Item	Amount
Lower Range Estimate	$19,207,500
Higher Range Estimate	$36,615,000

The development of these estimates can be found in Section 3 of this report.

POWER SUPPLY COSTS

R. W. Beck has assumed the municipal electric utility will contract for power supply from others at prevailing market rates for wholesale electricity supply. A market price study for the Southwest Power Pool ("SPP") was prepared to identify future market prices. This study is provided in Section 6 of this report.

These resulting market prices, expressed in average $/MWh are shown in Table ES-3 below.

Table ES-3
SPP MARKET PRICE FOR POWER
($/MWh)

Year	Energy	Capacity	All-In Energy
2002	$27.71	$7.72	$35.43
2003	$28.23	$8.53	$36.76
2004	$29.13	$9.44	$38.58
2005	$30.47	$10.32	$40.79
2006	$32.18	$9.95	$42.14
2007	$33.20	$11.50	$44.70
2008	$35.08	$11.04	$46.11
2009	$36.19	$11.37	$47.56
2010	$37.16	$11.86	$49.02
2011	$38.57	$11.80	$50.36
2012	$39.15	$12.94	$52.09
2013	$40.13	$13.26	$53.39
2014	$41.05	$13.57	$54.62
2015	$41.91	$13.85	$55.76
2016	$42.70	$14.11	$56.81
2017	$43.41	$14.35	$57.76
2018	$44.05	$14.56	$58.61
2019	$44.61	$14.75	$59.36
2020	$45.18	$14.93	$60.11
2021	$45.75	$15.12	$60.88

STRANDED INVESTMENT

The City may be required to compensate WRI for the reduced value of any remaining KGE assets which results from the acquisition of the distribution facilities within Wichita. The term stranded investment applies to such instances, which are typically related to generation facilities more costly than current market prices can support. Due primarily to the high cost of Wolf Creek Nuclear Generating Station, Beck expects that WRI will allege that it will incur stranded investment should the City municipalize. It should be noted that a final determination of the estimate of stranded cost would be made by a FERC judge. This determination could result in an assessment of zero stranded costs for KGE. Based on information provided by KGE, Beck has made a conservative estimate of the potential stranded investment to be approximately $145 million (Table ES-4). This does not imply that the City should concede the issue of the existence of stranded investment. Stranded costs are discussed in Section 5 of this report.

Table ES-4 POTENTIAL STRANDED INVESTMENT	
Item	**Amount**
Stranded Cost Obligation Estimate	$145,000,000

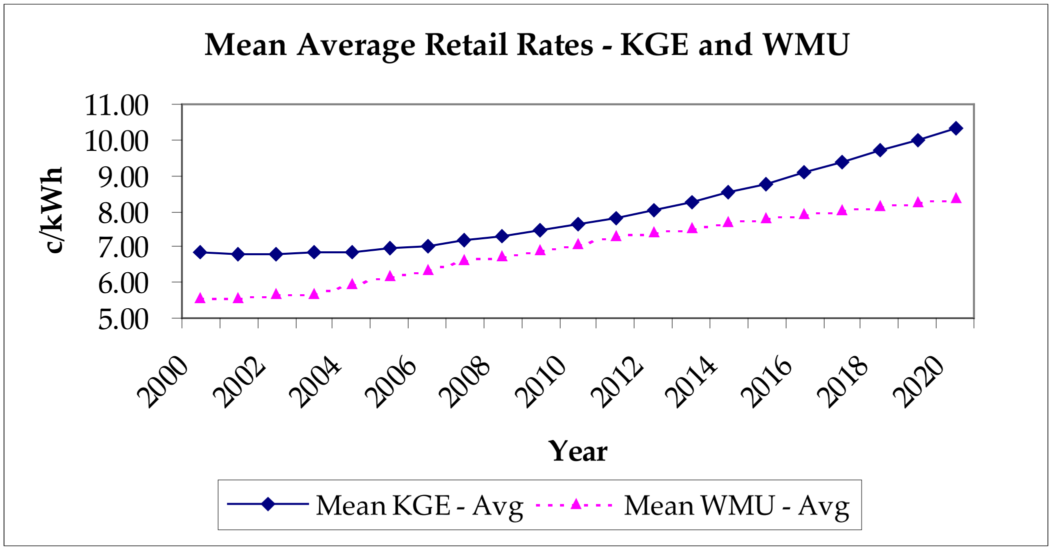
There will be additional costs incurred to start up the municipal electric utility, such as financing costs, initial working capital, reserve fund balances and other start up costs, all of which are discussed in later sections of this report. An estimate of the initial financing amount required to become operational, is provided in Table ES-5.

Table ES-5 MUNICIPAL UTILITY FINANCING	
Item	**Amount ($ millions)**
Facility Cost*	$336.7
Possible Stranded Investment	$145.3
Severance Cost	$36.6
Utility Reserves & Operating Funds	$123.7
Bond Issuance Fees	$23.3
Total Bond Principal	$665.6

*Includes distribution assets, general plant and acquisition related costs.

The resulting average municipal utility rate is compared to the KGE rate in the following figure (Figure ES-2). For the purposes of the report, the City's electric utility is referred to as the Wichita Municipal Utility ("WMU").

Figure ES-2



Note: WMU = Wichita Municipal Utility

As can be seen above, the average expected municipal utility rate varies from 7 to 19 percent lower than the average expected KGE rate (Table 8-2 in Section 8 of this report contains the resulting average rates in ¢/kWh).

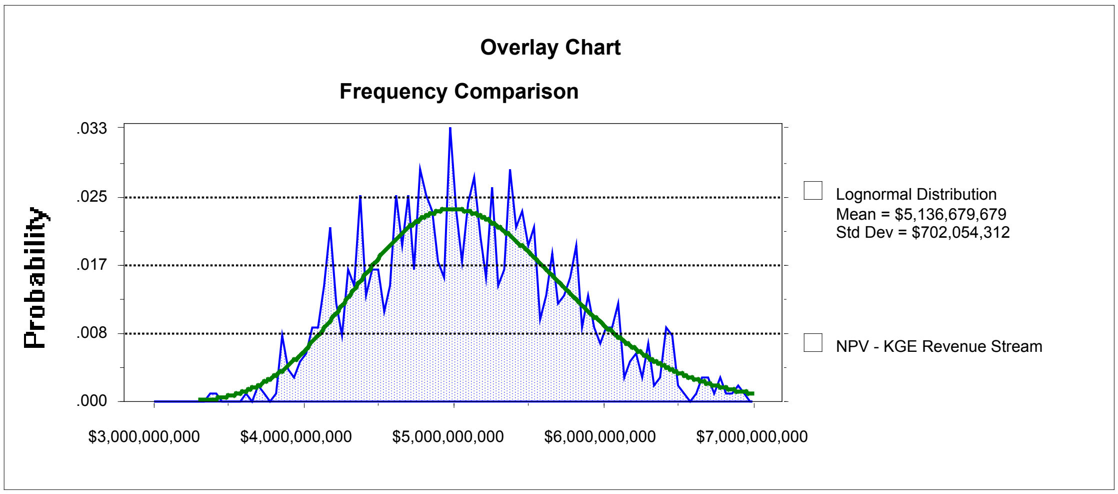
The municipalization feasibility study compares the costs of the KGE operations with the costs of the municipal operation over a 20-year forecast period, from 2001-2021. A variety of assumptions were made in this study, from inflation to the price of fuel for generation of electricity. Typically, these assumptions are made as single value estimates, or point estimates (i.e., 2.5 percent for inflation). As a single value estimate, these assumptions are always subject to uncertainty. Therefore, Beck utilized probability distribution functions for a variety of assumptions made in this study. These distribution functions provide for a range of possible inputs to the economic model and thus a range of possible economic impacts as a result of municipalization. This approach provides the City with a more in-depth understanding of the feasibility of municipalization.

FINANCIAL AND ECONOMIC RESULTS

As noted above, the economic impact of this study is defined as the difference between the costs of the continued KGE system and those of a municipal system. These costs were determined from the amount of revenue required to obtain, maintain, and operate the municipal system over the 20-year study period (these funds are referred to as the "revenue requirement"). Costs were recovered by average retail electricity rates applied to the electric load utilized by the citizens of Wichita. This resulted in two projected revenue streams, one for the KGE and one for the municipal system. To assess the impacts over the entire study period, the net present value ("NPV") of the difference in the revenue streams was developed. As probability distribution functions were utilized to describe certain assumptions underlying the cost forecasts, the end results are also described as probability distribution functions.

The expected value of the net present value of status quo costs; that is continued KGE operation, is approximately $5.1 billion over 20 years. See Figure ES-3, below.

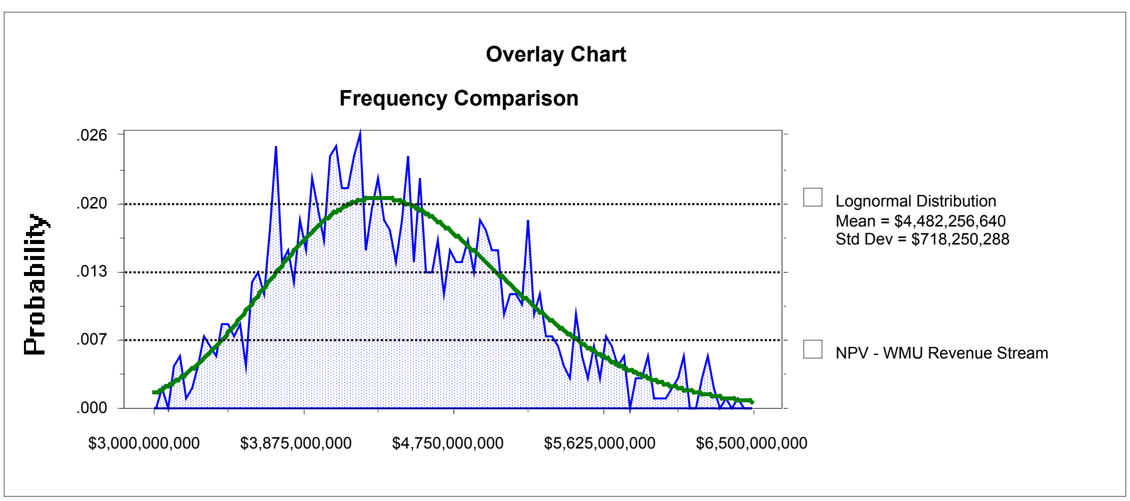
Figure ES-3
KGE – NPV OF RETAIL RATE REVENUE



Note: A lognormal distribution was utilized due to its unique mathematical properties.

The expected value of the net present value of forecasted municipal operations costs is approximately $4.5 billion. See Figure ES-4, below.

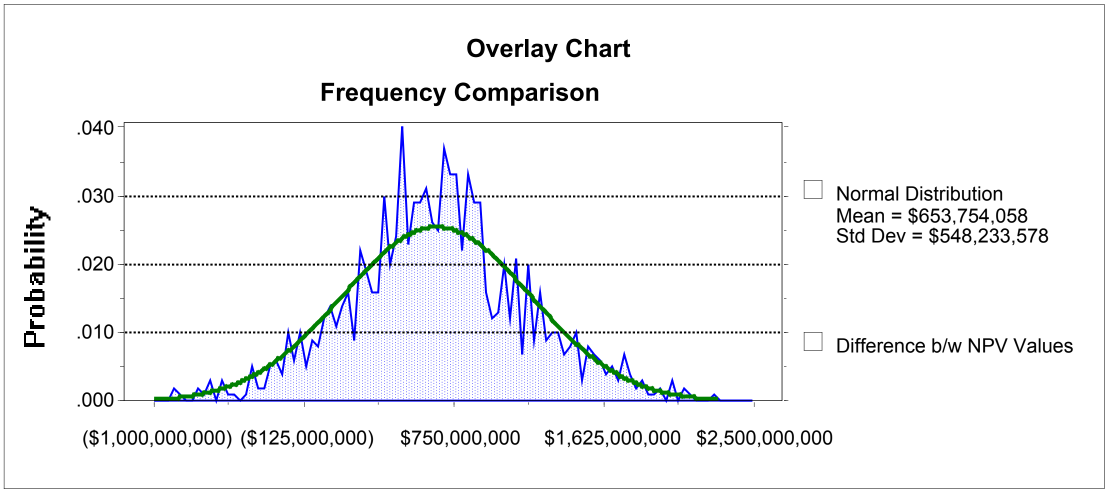
Figure ES-4
CITY SYSTEM – NPV OF RETAIL RATE REVENUE



Note: WMU = Wichita Municipal Utility
A lognormal distribution was utilized due to its unique mathematical properties.

The expected value of the difference (KGE-WMU) between the net present values for these two utility operations is approximately $654 million. See Figure ES-5, below.

Figure ES-5
NPV SAVINGS (KGE-CITY SYSTEM)



The results of the economic analysis can be reduced to an expected net present value of benefits from municipalization equal to approximately $654 million. However there are numerous details and nuances contained in the study which are too lengthy to be discussed in this Executive Summary. Section 8 of this report contains a significant amount of detail regarding the financial analyses, interpretation of the probabilistic results and a discussion of risk factors related to the results.

OTHER CONSIDERATIONS

Section 9 of this report contains a discussion of qualitative issues the City should consider, in addition to the results of this economic assessment in order to make a decision to proceed with the consideration of initiating the operation of the City's existing municipal electric utility. Important considerations are as follows:

- The time and costs involved in a contested acquisition of KGE assets
- The timing and extent of electric utility restructuring which may occur in Kansas and the effects it may have on KGE, a municipal utility and the potential for achieving some of the benefits from municipalization by way of the competitive markets which could result
- The potential for rate and regulatory litigation to achieve rate parity with KPL
- The potential for synergies not considered in our economic analysis

This study, and consideration of other qualitative measures mentioned above, will not provide sufficient information for the City to make a definitive decision to municipalize. Rather, this study will allow the City to determine if it wishes to proceed with the process of examining the municipal option. A positive decision to proceed at this time will lead to a further examination of the costs involved in further developing the City's municipal utility. The results of the detailed cost study will provide the City with the information necessary to make a definitive decision on whether to become an operating municipal utility. Our discussion at the end of Section 9 identifies action items leading to the implementation of an operating municipal electric utility.

SECTION 1
INTRODUCTION, BACKGROUND AND METHODOLOGY

Historically, the City of Wichita ("City" or "Wichita") has granted a franchise to Kansas Gas and Electric ("KGE") to allow KGE the use of its public rights-of-way to operate an electric utility within the City. In 1992, the Kansas Power and Light Company ("KPL") merged with, and acquired the assets of, KGE forming a new electric utility company, Western Resources, Inc. ("WRI"). KGE is now a wholly-owned subsidiary of WRI and KPL is an operating division of WRI. However, WRI operates as a single integrated electric utility using generation resources of both KPL and KGE to serve the combined WRI load.

At the time of the merger, KGE's retail electric rates were significantly higher than those of KPL, primarily due to the high cost of the Wolf Creek Nuclear Generating Station where KGE owns a 47 percent interest. The Kansas Corporation Commission, ("KCC") was required to approve the merger of KPL and KGE in order for it to be completed. In connection with the KCC approval creating WRI, and a retail rate proceeding following the merger, the KCC examined the issue of the large rate disparity between KPL and KGE. The City offered evidence that the rate disparity should be eliminated. The KCC ultimately ruled that eliminating this rate disparity is desirable, and ordered that a disproportionate amount of the cost savings expected from the merger be used to lower KGE's retail rates to reduce the overall rate disparity.

While KGE customers, including those in Wichita, enjoyed rates which were reduced in several increments in the years after the merger (the last occurring in the summer of 1999) the rate disparity continues at a significant level. KGE customers pay rates that are 25-28 percent higher than KPL customers, which is referred to the rate disparity within this report. This rate disparity not only creates an economic burden on the citizens in Wichita, but is impacting future economic development in the Wichita community.

The City continues to believe strongly that the disparity is inappropriate, onerous, not cost justified and is an unfair economic burden on the community. To that end, the City has aggressively pursued every available forum for addressing the rate disparity. These forums have included rate, merger and complaint proceedings at the KCC and the Federal Energy Regulatory Commission ("FERC") in Washington, D.C. While certain of these regulatory actions are still being pursued, and could ultimately lead to a reduction in the rate disparity, the City has determined that it should concurrently examine other mechanisms for addressing this economic burden.

One alternative is for the City to acquire the electric distribution facilities of KGE within the City and create a City-owned municipal electric utility. In this way, the City would control the retail electric rate levels within the City, and would not have to rely upon an outside regulator (KCC or FERC) to address the retail rate disparity. The timing for the City to examine establishment of municipal electric utility is attractive as KGE's franchise is near expiration.

KGE'S ELECTRIC FRANCHISE

As noted above, the City granted a 20-year franchise to KGE for operation of an electric utility within the City boundaries. The current franchise expires on March 1, 2002. The City and KGE representatives are currently engaged in various discussions related to the rate disparity which includes discussions regarding an extension of the current franchise or the development of an entirely new franchise. Until, or unless, such a franchise renewal or extension is signed, it is assumed that the termination of the current franchise will provide the opportunity for the City to decline to renew a franchise with KGE. Additionally, this event will provide the City with an opportunity to acquire KGE facilities as they would no longer have a contractual right (i.e., franchise agreement) to occupy public rights-of-way within the City.

FEASIBILITY ANALYSIS

Establishing an operating municipal electric utility in Wichita is a significant undertaking, requiring the formation of a utility organization with trained staff, acquiring facilities of KGE (possibly through condemnation) arranging for power supply to serve the City's electrical load, severing the KGE facilities within the City from the remainder of the KGE system and reconfiguring lines and substation to keep the municipal system and the KGE system electrically reliable. Collectively, these activities are referred to as "municipalization" and are defined for this report as activities required to establish a municipal electric utility in Wichita. Such an effort would only be undertaken if there was a reasonable expectation that a municipal electric utility could achieve significantly lower rates than current KGE rates, thereby achieving the City's goal since the 1992 merger of KGE and KPL.

In order to assess the financial feasibility of achieving such a result on a preliminary basis, the City engaged R. W. Beck, Inc. ("Beck") to perform a Municipalization Feasibility Study ("Feasibility Study" or "Study"). This report contains the results of Beck's analyses including findings, conclusions and recommendations.

METHODOLOGY

The methodology used to examine the feasibility of municipalization is straightforward and is expressed as the difference between the expected costs of continued KGE operation and the expected cost of municipal operations, as provided in Figure 1-1 below.

Figure 1-1

Expected Costs of Continued KGE Operation
– Expected Costs of Municipal Operation
= Benefits of Municipalization

It is important that the cost comparison be performed over a period of time sufficiently long to give confidence that the results are not short term. This analysis uses a study period of 20 years, beginning in 2001 and ending in 2021. The following discussion addresses the cost components included in this analysis in a general manner. A more detailed discussion is presented in the following sections of this report. For the purposes of the report, the City's electric utility is referred to as the Wichita Municipal Utility ("WMU").

KGE COSTS

As a regulated electric utility, KGE is required to file certain financial and operating information with regulatory agencies, primarily the KCC, FERC and the Securities Exchange Commission ("SEC"). Beck used publicly available information, primarily from these sources, to develop historical cost and operating information for the years 1990 to 1999. Using the historical information as a beginning point, Beck developed a forecast of costs of future KGE operation for the years 2001-2021. The resulting cost forecast for KGE became the benchmark for measuring municipal utility operation costs.

For purposes of this study, Beck has assumed that WRI will continue to develop and support KGE rates on a stand-alone basis rather than combining its KPL and KGE divisions into a single, integrated utility for ratemaking purposes. Although KGE costs have been developed on a stand alone basis, Beck has developed KGE's generation estimates consistent with exchanges made with other utilities, including KPL. Section 7 of this report discusses our KGE cost analysis in further detail.

MUNICIPAL UTILITY COSTS

The cost of establishing and operating a municipal utility and the appropriate section of this report in which it is discussed are provided below:

- Costs of acquisition of KGE facilities in the City (Section 2).

- Costs of severance of KGE facilities in the City (Section 3).
- Costs to acquire a power supply for the Wichita Municipal Utility (Section 6).
- Costs the City may be required to pay WRI for Stranded Investment (Section 5).
- Costs to operate the Wichita Municipal Utility (Sections 4 and 7).
- Cost of financing the acquisition (Section 7).

A general introduction of these issues is provided below.

ACQUISITION COSTS

Beck has developed a preliminary estimate of the costs of acquisition of KGE facilities within the City. In order to develop these acquisition costs, an estimate of the extent of electric facilities within the City was required. Beck's analysis is based upon an examination of the cost of all KGE facilities, from publicly available sources as mentioned earlier, and a proration of the costs of all KGE facilities to areas within the City. In developing this estimate, Beck relied upon certain property tax records available from the Kansas Department of Revenue which provided a reasonable basis to develop an estimate of KGE facilities within the City.

Once an estimate of the cost of facilities in the City has been completed, the facilities must be valued for purposes of determining the price the City would be willing to pay WRI. This could be a negotiated price, reached in agreement with WRI. WRI has publicly announced it's desire to sell, or merge, its company with another, however, historically utilities have generally not voluntarily agreed to sell distribution facilities. (In a recent notable exception, Montana Power Company is actively pursuing a voluntary sale of its distribution system, following a voluntary sale of its generation facilities a year earlier.)

Given the recent negotiations between the City and WRI, Beck has assumed that the City would acquire the KGE facilities by condemnation or some other similar process. In such an action, the valuation of the acquired properties would be determined by a condemnation court action.

Beck's analyses are based upon a condemnation valuation range expressed as Original Cost Less Accumulated Depreciation on the lower end to Replacement Cost Less Accumulated Depreciation on the upper end. A detailed discussion of the development of the acquisition cost estimate appears in Section 2 of this report.

SEVERANCE COSTS

In order to acquire and operate the KGE distribution facilities within the City, the electrical power system within the City must be segregated from the remaining KGE system. This could be accomplished administratively or it may require construction of certain new facilities. New facilities would allow the municipal system to operate and to ensure KGE's remaining system is electrically intact and reliable. The costs of isolating the municipal system from KGE and reconfiguring both the KGE system and the municipal system are termed "Severance Costs."

Severance Costs can be minimized in certain (and possibly most) instances by metering and billing arrangements which effectively transfers customers from an accounting and business standpoint rather than constructing significant and costly new electrical facilities. This approach can be especially effective in cases where a small pocket of customers reside inside the City limits but are served primarily from KGE's electrical system outside the City.

Minimizing severance costs in this manner would require a significant amount of cooperation between KGE and the City. Because the level of cooperation is unknown, two estimates for severance costs have been developed for this study; one assumes a moderate level of cooperation from KGE, and one assumes essentially no cooperation. A third option is discussed, which assumes a high level of cooperation from KGE, however a cost estimate for this option was not developed.

Actual severance of KGE's facilities along an irregular City limit boundary will require a very detailed design of facilities, a plan of disconnection and reconnection of distribution circuits and facilities, and the integration of required new facilities. For purposes of this Feasibility Study, Beck has not performed such detailed system design and cost analysis.

Beck did however, perform a field review by experienced electric utility design engineers of KGE's system along the City's boundaries. A general severance estimate was developed based upon the field review of KGE facilities. A detailed discussion of Beck's severance examination and the related cost estimates can be found in Section 3 of this report.

POWER SUPPLY

KGE owns a significant amount of electric generation facilities. These facilities, together with generation facilities owned by KPL, are used collectively by WRI to meet the combined loads of KPL and KGE. Only a small amount of KGE owned generation facilities reside within the City. This Feasibility Study assumes that the City would not acquire generation facilities. Rather, the municipal electric utility will be a distribution utility and will contract for power supply from third party suppliers in order to obtain its power supply needs. (The municipal utility will own and operate an electric transmission system required to connect its distribution system to the wholesale transmission system, as necessary.)

The costs of power supply are typically the largest costs incurred to meet customers loads, often comprising as much as 70 percent of the total delivered electricity costs. As such, the forecast of power supply costs for the municipal utility is a critical component of the Feasibility Study.

In order to estimate power supply costs for the study period, Beck developed a regional model of the Southwest Power Pool ("SPP"), the regional electric reliability council including WRI and other electric utilities serving Kansas, Oklahoma, Missouri, Arkansas and parts of Louisiana and Texas.

Due to the deregulation of electric utilities at the wholesale level mandated by the FERC and requirements that transmission system owners make available their transmission systems to wholesale customers, the City, as a wholesale purchaser for its municipal electric utility, will be able to access the SPP for its power supply.

Beck's model provides a forecast of wholesale market prices for the region. This feasibility analyses uses these forecasted market prices as the basis for the municipal electric utility power supply costs. (For consistency, these same market prices are used to determine the future costs of KGE operation when it does not have sufficient generation to meet forecasted loads). The details of Beck's market price forecast can be found in Section 6 of this report.

STRANDED INVESTMENT

The City's acquisition of KGE's distribution facilities within the City may reduce the value of other KGE assets. If this occurs, the City may be obliged to compensate KGE for this reduced value. These costs are generally described as "Stranded Investment," as the facility investments are essentially stranded without a way for the owning utility to fully recover its invested costs. It is not entirely clear whether stranded investment will exist in this situation and the ultimate decision will likely be made during a FERC hearing.

The most significant potential stranded investments are related to generating assets. In the case of the City's acquisition of the KGE customers and facilities within the City, KGE is expected to lose approximately 1,150 MW (megawatt) of retail customer load. This reduction in load will allow WRI to use the generating capacity previously used to serve Wichita customers, to serve other customer's loads or new load growth on the KPL or KGE system, as well as to sell this capacity to others in the competitive wholesale market.

The FERC has ruled, as part of its deregulation of wholesale generation markets and open access to transmission systems, that "retail turned wholesale" situations (like that contemplated by the City) may require the payment of a stranded investment component. This stranded investment component is related to the reduced value, if any, of generation sold at market wholesale prices rather than used to serve retail customers. FERC has established a formulary procedure for developing an estimate of such stranded investment.

FERC's Order No. 888 also established an obligation for a generating utility to offer an estimate of its stranded costs to a requesting party. The City has requested and received such an estimate from KGE (a copy of which is included in Appendix A). While FERC has established guidelines for the quantification of stranded investment, interpretation of the guidelines and formula approach is typically required. As mentioned above, this interpretation will likely be made during a FERC hearing and will be based upon the specifics of the situation at hand.

Beck has performed an independent assessment of the potential stranded investment obligation which may result from the operation of a municipal electric utility which differs significantly from KGE's response. Beck's analysis of stranded investment is guided by the City's legal advisors with respect to application of FERC rules and case precedent, however, it does not limit the possibility that during a FERC hearing the City could present a case that stranded costs do not exist in this situation.

Beck's stranded investment estimate is credible, defendable and conservative in light of the specifics of the Wichita situation. It is beyond the scope of this study to rebut KGE's showing, however KGE's stranded cost estimate of $1.6 billion is significantly exaggerated in the following ways:

- It assumes market prices are much lower over time than reasonable market price forecasts.
- It does not account for distribution system revenues, as required by FERC.
- No consideration is given to the time value of money, as required by FERC.

Beck's stranded cost estimate is provided in Section 5 of this report.

MUNICIPAL OPERATIONS COSTS

For purposes of the Feasibility Study, Beck has assumed that the costs of operation of a municipal distribution utility in Wichita are similar to the costs KGE incurs in operating its system in Wichita. In order to estimate such costs, Beck has developed a methodology which examines KGE's costs for operations of its entire system and allocates those costs to the operation of the smaller system within Wichita. These costs are primarily Operations and Maintenance ("O&M") costs associated with a distribution utility. Certain distribution costs are incurred which are proportional to the number of customers served. These costs are therefore allocated to the City on a customer basis. Other distribution costs are incurred which are proportional to load (i.e., kilowatts of demand), energy (kilowatt-hours of use) or cost of the facilities involved in the operation. Allocation factors for all of the distribution costs incurred in operation of the KGE system were developed and used to determine an estimate of O&M costs for the distribution system within the City.

As a benchmark analysis, the resulting O&M costs of operation of the municipal utility system were compared to O&M costs reported by other similarly sized and situated municipal electric utilities. Unless this benchmark analysis indicated otherwise, O&M estimates based upon the above allocation methodology were utilized. In this manner the municipal O&M cost estimate is consistent with the KGE O&M costs estimated under continuing KGE operations. As a result, the 20-year cost forecast is not biased for or against municipalization due to different distribution O&M estimates for operation of essentially the same facilities.

Finally, the municipal utility operations costs were adjusted to reflect start-up costs. A detailed staffing and organization plan for a municipal utility was beyond the scope of this study. Additionally, no assumptions concerning how the utility would be integrated into the City government, and its other departments, were incorporated into this analysis. Section 4 of this report discusses a typical organization and staffing for the municipal utility in a general manner. The details of the operation of the utility and its integration into City government would be performed at a later date when the City has more certainty regarding its schedule for implementation of a municipalization plan.

In order to capture reasonable start up costs for the municipal utility, two key assumptions have been included in this analysis. These are as follows:

- Legal, engineering and financial costs involved in achieving the acquisition of KGE's facilities within the City through condemnation or otherwise will amount to $5 million.
- The first three years of municipal operations costs will be 15 percent, 10 percent and 5 percent higher, respectively, than otherwise expected for a mature operation as the City learns the business of an electric distribution utility.

Section 7 provides further discussion of the costs associated with the municipal utility operations.

FINANCING THE ACQUISITION

Municipal electric utilities are generally financed through the issuance of revenue bonds. The revenue bondholders have a lien on the revenues of the municipal utility as security, or collateral, for the outstanding revenue bonds not yet redeemed. Typically, municipal electric utility revenue bonds bear interest which is exempt from federal income taxes to the holders of the bonds. As a result, municipal revenue bonds are an attractive, low cost means for municipal utilities to acquire the financial capital needed to own and operate electric utility systems, which are by their very nature, capital intensive businesses.

The Internal Revenue Service has issued restrictions on the exemption from taxes of the interest on municipal revenue bonds, where such bonds are used to acquire properties from taxable entities such as KGE and WRI. Because the interest is not tax deductible, holders of the bonds require a higher interest rate in compensation.

This Feasibility Study assumes all of the capital required to acquire KGE facilities is acquired by issuing taxable municipal bonds. A further discussion of the overall financial analysis is contained in Section 7 of this report.

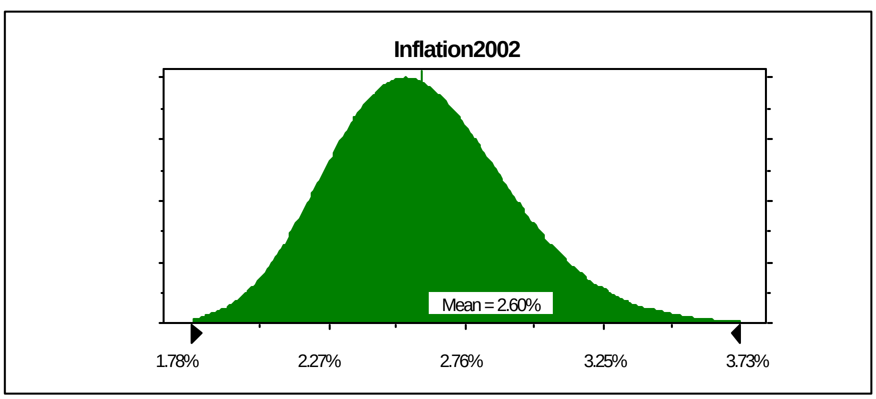
FINANCIAL AND ECONOMIC ANALYSIS

As mentioned earlier, the municipalization feasibility study compares the costs of KGE operation with the costs of municipal operation over a 20-year forecast period. In addition to the costs identified earlier in this discussion, numerous assumptions are required to develop the prorated financial operating results or "pro forma" of KGE and the municipal utility. These assumptions address such matters as inflation rates, fuel prices, load growth and financing costs. Beck has relied upon publicly available data to base certain assumptions, where available. In cases where such independent data is not available, Beck has developed reasonable assumptions based upon its own experts opinions and experience in performing similar financial and economic analyses.

Regardless of the source of the assumptions used in this analysis, they remain just that – assumptions regarding future conditions which cannot be predicted with certainty. While the assumptions used are reasonable for the purposes of the municipalization feasibility study, these assumptions are based upon professional judgment and could vary from those used in the analyses.

In order to acknowledge the uncertainty in assumptions used to forecast future conditions in these analyses, and its effect on the results, several important assumptions have been incorporated into the analyses as probability functions rather than specific values or point estimates. These probability functions were incorporated using a probability software package known as *Crystal Ball*™. For example, inflation is assumed to be expressed as a lognormal function with a mean of 2.6 percent and a standard deviation of 0.32 percent (Figure 1-2). A lognormal function is used due to its unique mathematical properties.

Figure 1-2



Lognormal distribution with parameters:

Mean	2.60%
Standard Dev.	0.32%

Selected range is from 0.00% to +Infinity

While the analytical effort, and tools required to perform an probability analysis, are considerably more sophisticated than those required to perform a non-probabilistic analysis, the expression of confidence levels of certain outcomes provides the City a more in-depth understanding of the feasibility of municipalization. A more detailed discussion of the financial analysis, including the probability analyses, is provided in Section 8 of this report.

SECTION 2
FACILITIES VALUATION

A large portion of the price associated with any municipalization effort is related to the acquisition of the property by the start-up municipal organization. This section of the report provides an estimate of the value of the KGE transmission and distribution facilities that would be acquired by the City. It was determined that the City would not acquire any of the production facilities of KGE.

VALUATION ANALYSIS

The valuation analysis for the KGE transmission and distribution facilities within the City consisted of the following steps:

- Obtaining useful data on the cost of property within the City.
- Removing any generation facilities costs from the above data.
- Developing in service data for property located in the City.
- Using escalation factors, developing replacement cost and accumulated depreciation factors for KGE property located in the City.
- Developing the value of the transmission and distribution facilities in the City.

DATA SOURCES

Information used to perform the valuation of the KGE facilities was obtained primarily from four sources:

- **FERC Form No. 1 annual report for KGE (1990-1999).** The FERC Form No. 1 was used to obtain original cost information on the total KGE system and original cost data on individual generating facilities owned by KGE. In addition, the FERC Form No. 1 was used to develop the average age and estimated useful life of the transmission and distribution facilities. This FERC data was obtained via Beck's *PowerDat*™ subscription service from Resource Data International ("RDI").
- **Valuation records prepared by the State of Kansas, Division of Property Valuation for KGE.** These records were used to develop an allocation of the original cost of KGE facilities located in Sedgwick County compared to original cost of the total KGE system.
- **Handy-Whitman Index ("HWI") of Public Utility Costs, Bulletin No. 151.** The HWI was used to escalate the original cost of the KGE transmission and distribution property to the year of valuation.

- **The Electric Kansas Supplemental 1998 and 1999 Annual Reports filed by KGE to the Kansas Corporation Commission (the "Supplemental Report(s)").** The data from the Supplemental Report was used to develop the allocation of Sedgwick County costs to the City.

All information used to estimate the value of the KGE transmission and distribution facilities located in the City was obtained from public documents.

PLANT-IN-SERVICE – SEDGWICK COUNTY

Plant-in-service (or original cost) figures from the entire KGE system were obtained from the FERC Form No. 1. For the year 1999, the beginning of year and end of year balances were averaged to obtain the total plant-in-service. Table 2-1 below indicates the total KGE system plant-in-service values for 1999.

Table 2-1
KANSAS GAS AND ELECTRIC COMPANY
PLANT-IN-SERVICE FOR YEAR 1999

Intangible Plant	$11,902,961
Production Plant	$1,933,952,103
Transmission Plant	$259,988,273
Distribution Plant	$506,636,261
General Plant	$72,751,801
Total Plant-in-Service	$2,785,231,399

Source: RDI, 2000

In order to develop an estimate of the original cost for the KGE facilities located in Sedgwick County, the assessed valuation records obtained from the Department of Revenue were used. According to individuals at the Department of Revenue, the total assessed value of the KGE system is developed and allocated to each county (as well as each taxing unit within the county) on the ratio of the original cost of the property located in the county as a percentage of the original cost of KGE facilities. According to the Department of Revenue, the original cost figures were supplied by KGE.

For the 1999 assessment period, the assessed value of the total KGE system was approximately $464.1 million. For this same time period, the assessed value of the KGE property in Sedgwick County (in which the majority of the City exists) was approximately $86.7 million. The ratio of these figures, 18.7 percent, indicates that the original cost of the KGE facilities located in Sedgwick County should be approximately 18.7 percent of the original cost of the total KGE system facilities. Applying this ratio to the above plant-in-service costs results in an estimated original cost of $520.4 million for KGE property in Sedgwick County. From this amount the original cost of the generation facilities located in Sedgwick County (the Murray Gill and Gordon Evans generation stations) were deducted. The estimated original cost of the Gill and Evans stations was approximately $109.1 million as contained in the FERC Form No. 1. This results in an original cost of KGE non-generation property facilities located in Sedgwick County of $411.3 million.

This resulting original cost was then split between transmission and distribution plant. Although some of the non-generation facilities plant-in-service developed for Sedgwick County would be for general plant (since most of KGE's general plant would be located in the City), a conservative assumption was made that all of this plant-in-service is transmission and distribution facilities.

The allocation between transmission and distribution was based on the total amount of transmission and distribution plant-in-service for the total KGE system (Table 2-1). The ratio of the transmission plant to the total of the transmission and distribution plant was applied to the $411.3 million value to determine the transmission plant-in-service within Sedgwick County. A similar calculation was performed for the distribution system. Table 2-2 below provides the transmission and distribution plant-in-service values calculated for Sedgwick County.

Table 2-2
SEDGWICK COUNTY
TRANSMISSION AND DISTRIBUTION PLANT-IN-SERVICE FOR THE YEAR 1999

Transmission Plant	$139.5 million
Distribution Plant	$271.8 million
Total	$411.3 million

These amounts, for facilities within Wichita, compare favorably to the percentage of customers, load and energy in Wichita.

AVERAGE IN SERVICE DATE

As discussed in Section 3, Beck's review found that the KGE facilities located in the City were in good condition. In addition, we performed a limited review of KGE transmission and distribution facilities not located within the City and found that they were in good condition as well. Based on this, Beck assumed that the average age of the transmission and distribution facilities located within the City could be approximated by the average age of the transmission and distribution facilities in the KGE total system.

From the FERC Form No. 1 information, Beck obtained the total amount of accumulated depreciation, the depreciation expense and the amount of depreciable plant for the KGE system transmission and distribution facilities. To calculate the average age of the transmission and distribution plant, the accumulated depreciation was divided by the depreciation expense. Table 2-3 below indicates the average calculated age of the transmission and distribution facilities by KGE.

Table 2-3
KANSAS GAS AND ELECTRIC COMPANY
AVERAGE CALCULATED AGE OF TRANSMISSION AND DISTRIBUTION FACILITIES

Transmission	16.2 years (1983)
Distribution	12.7 years (1986)

DEVELOPMENT OF REPLACEMENT COST AND DEPRECIATION

With the original cost estimate and average calculated in service date, an estimate of the replacement cost of the KGE transmission and distribution facilities in Sedgwick County was performed. Using the average in service date information, the HWI was used to escalate the original cost figures to a current estimate of the replacement cost for these facilities. The HWI was used for the total transmission plant and the total distribution plant, since data was not available by individual account. The replacement costs developed for the KGE transmission and distribution facilities in Sedgwick County are provided in Table 2-4 below.

Table 2-4
SEDGWICK COUNTY
TRANSMISSION AND DISTRIBUTION REPLACEMENT COSTS

Transmission Plant	$217.2 million
Distribution Plant	$371.2 million
Total	$588.3 million

Note: Numbers may not add precisely due to rounding.

Using data from the FERC Form No. 1, an estimate was made of the amount of accumulated depreciation for the KGE transmission and distribution properties. The accumulated depreciation through 1999 was reported to be 40.5 percent and 37.2 percent of the depreciable plant for all KGE transmission and distribution facilities, respectively. These percentages were used to calculate the amount of depreciation for both the original and the replacement costs for the transmission and distribution facilities in Sedgwick County. The depreciation was deducted from the original cost and replacement cost to obtain the original cost less depreciation ("OCLD") and the replacement cost less depreciation ("RCLD") figures for the KGE transmission and distribution facilities in Sedgwick County. Table 2-5 below presents the OCLD and RCLD estimates developed.

Table 2-5
SEDGWICK COUNTY
ESTIMATED TRANSMISSION AND DISTRIBUTION OCLD AND RCLD

	OCLD	RCLD
Transmission Plant	$83.0 million	$129.2 million
Distribution Plant	$170.8 million	$233.2 million
Total	$253.7 million	$362.4 million

Note: Numbers may not add precisely due to rounding.

ALLOCATION OF SEDGWICK COUNTY TO THE CITY

Once the calculation of OCLD and RCLD was developed for the Sedgwick County transmission and distribution facilities, an allocation for those properties located in the City was developed. The Supplemental Report filed with the KCC contains data for each community served by KGE. This data includes total revenue, energy sold, and the number of customers served within each community. From this information, the data for those communities that are located within Sedgwick County was extracted. An allocation of the data for the City as compared to total Sedgwick County was performed for total revenue, energy sold and number of customers. These were averaged to develop an allocation to the City of 89.2 percent of the Sedgwick County total. This allocation was applied to the Sedgwick County OCLD and RCLD figures calculated above to determine the OCLD and RCLD figures for KGE transmission and distribution facilities in the City. Table 2-6 below summarizes the results.

Table 2-6
CITY OF WICHITA
ESTIMATED TRANSMISSION AND DISTRIBUTION OCLD AND RCLD

	OCLD	RCLD
Transmission Plant	$74.0 million	$115.3 million
Distribution Plant	$152.3 million	$208.0 million
Total	$226.4 million	$323.3 million

Note: Numbers may not add precisely due to rounding.

From the development of the OCLD and RCLD figures, the indication of the value of the KGE property that would be acquired by the City would be between $226.4 million and $323.3 million. For the purpose of the analysis included in the report, it was conservatively assumed that the value of the properties to be acquired would be at the high end of this range, at $323.3 million. This is the value utilized in the pro forma for the acquisition price (see Section 6).

PHYSICAL REVIEW AND SEVERANCE ESTIMATE

The operation of a municipal electric utility will require the City to acquire some of KGE's existing assets. In order to acquire KGE facilities and operate them as a municipal electric utility, the facilities must be somehow segregated from the KGE system. The cost estimate associated with segregation of the facilities is referred to as the "severance cost." This section describes the methodologies utilized to determine the severance costs associated with the City's municipalization effort.

In order to determine severance costs, a field review of the existing system to be acquired was conducted. This review was limited to assets that could be observed from public areas; no detailed inspections of KGE's facilities were performed.

For the purposes of this study, severance consists of the physical separation or administrative segregation of the property from the KGE system in such a way that the municipal utility and KGE can each own all and operate most of its own set of facilities. Since KGE property winds in and out of the City boundaries, some form of severance needs to be developed to ensure that both the City and KGE can operate their facilities effectively.

Three scenarios related to the determination of severance costs were developed for this study. The first scenario assumes strong cooperation with KGE or a KCC order to create an administrative severance (Case 1). The second scenario assumes a moderate level of cooperation with KGE upon the acquisition of property in the City (Case 2). The third level assumes very little cooperation with KGE (Case 3).

In most instances it was assumed that severance occurred at the City limits. For the commercial loads that were adjacent, but outside the City limit, the assumption was made that the City would serve these loads. In Cases 1 and 2, the level of cooperation with KGE would likely require arrangements which include transfer billing agreements, transmission sharing and joint use of substations and poles between the City and KGE. In Case 3, with little or no cooperation with KGE, the severance requirements would likely include construction of some duplicate facilities. This section presents the results of a physical review of the electrical distribution system by function. This is followed by a presentation of the three cases for severance.

PHYSICAL REVIEW

This analysis included a field review of the physical condition of the existing electrical facilities. The review was limited to what could be observed from the street, without direct access to equipment or substations. Additionally, no design assessment or load flow analysis was conducted as part of this physical review. The results of this review are presented below according to the function of the systems reviewed, starting with the transmission system, followed by the substations and ending with the distribution systems.

SUB-TRANSMISSION FACILITIES (138 AND 69KV)

Transmission facilities located within the City are primarily at voltage levels of 69 kiloVolts ("kV") and 138 kV. There are some 345 kV facilities that are located just outside the City limits, however, we have assumed that these facilities would remain part of the KGE system and would not be acquired by the City.

The majority of the 69 kV transmission facilities are located on wishbone framing with an occasional steel tower for long spans or large angles. There are some newer 69 kV facilities that have been constructed on line post insulators. A few sections of older 69 kV facilities with unmatched insulators and slightly degraded structures were observed; however, this comprised a very small percentage of the system that was reviewed. A few substations in the downtown area appeared to have underground 69 kV lines associated with them. Although the condition of the underground facilities could not be reviewed explicitly, judging from the terminations at substations and the age of the development in the area, the underground construction appeared to be newer and is probably in good condition.

The 138 kV transmission facilities located outside the City and in the less developed areas within the City is mostly on H-frame construction. In more heavily developed areas, the 138 kV transmission facilities are on single wood poles with davit arms or post insulators. In addition, much of the newer construction is on steel or concrete poles. All of the 138 kV transmission facilities appeared to be in good condition.

Many of the transmission lines, as well as the distribution lines, have been strung with VR type cable. The VR cable is a twisted pair of conductors, which reduces wind induced vibration and galloping conductors caused by ice and wind. In other places, spiral vibration dampers have been used.

In general, the transmission facilities appear to be in good condition. The use of concrete poles and VR type cable implies a commitment to modern technology and construction techniques. Some transmission, especially on the east side of the City, has been constructed for 138 kV although it is currently operating at 69 kV. This also appears to indicate a progressive approach to transmission planning by KGE.

SUBSTATION FACILITIES

There appear to be two generations of substation facilities within the City. The older substations are high-bay construction and the newer substations are lower profile pipe-bus construction. There seems to be an equal number of each type of substation construction throughout the City. Most substations, especially those most recently constructed, have room for expansion. Only a few older substations appear to have reached their physical limits of expansion. The outside of most of the substations, as well as their equipment fencing and screen walls, appeared to be in good condition. It seems that all substations are equipped with some type of radio-frequency communication, although the level of remote monitoring and control could not be determined from this review.

Some older substations have equipment that needs paint. Also, as expected, the older substations have a large assortment of equipment types and vintages due to equipment replacement and expansion over the years. Several generations of circuit breakers, for example, may be present in the same substation.

One characteristic of many of the distribution substations is the use of multiple smaller transformers. It appears that the common design for the older high-bay distribution substations, and even some newer ones, is to use two, three, or more transformers, rated at about 7500 kVA. Each transformer has high-side fusing with a single metal-enclosed low-side breaker that supplies a single or double 12.5 kV feeder. It is unclear exactly why KGE has taken this approach, since the cost would be higher than normal. It does, however, provide for additional expansion capability, reliability and load growth. This type of construction may simplify severance because of its flexibility.

Most new substations use a few larger capacity transformers, and feed switchgear lineups instead of single breakers and feeders. Some of the newer 69 kV substations, especially on the east side of the City, are fully insulated for 138 kV operation with dual winding transformers. Conversion to 138 kV substations appears to be imminent. The new substation standard design appears to be two transformers with two lineups of 12.5 kV outdoor metal-enclosed switchgear, possibly with tie-breakers between the lineups. Severance by reconfiguring distribution feeders should be a relatively straightforward process.

DISTRIBUTION FACILITIES

Nearly all distribution facilities within the City are 12.5 kV, with just a very small amount of 5 kV facilities. Distribution is primarily on cross-arms, with the occasional use of pin or post-insulators in a “clean” configuration. The downtown area contains a lot of underground 12.5 kV distribution facilities, as do most of the newer subdivisions. Voltage support capacitors are in use throughout the City. Other miscellaneous equipment observed included gang-operated switches, fused cut-outs, surge arrestors, distribution transformers, and service drops; all of which appeared to be in good condition. The poles seem to be solid and in good condition. Some of the newer distribution feeders have been built on laminated wooden poles, especially at angles and deadends.

As expected, there is considerable distribution and transmission joint pole use. This may complicate severance in cases where the transmission and distribution facilities are owned by different entities.

Distribution along the City limits appears to not be specific to loads inside or outside the City boundary. If physical severance must occur exactly at the City limit, substantial distribution feeder and tap construction will have to be performed, especially on the south side of the City.

SUMMARY & CONCLUSIONS

Overall, the electrical facilities reviewed were in good condition. A sizable portion of the system is relatively new and KGE appears to have liberally applied modern technology and construction techniques to these facilities. Maintenance of the older facilities appears to have been adequate, at least as can be determined from this limited physical observation. Most substations and transmission corridors should be able to expand with City growth, as evidenced by capacity upgrades shifting from 69 kV to 138 kV.

SEVERENCE OF KGE PROPERTY

This section of the report provides a description of the severance issues and a cost estimate for the severance related to the municipalization effort. As mentioned previously, three cases were developed. Case 1 is the lowest cost option and assumes strong cooperation or a KCC order, assuming the City wants to own and operate facilities on behalf of KGE in limited circumstances. Case 2 assumes a moderate amount of cooperation by KGE, whereas Case 3 assumes very little cooperation at a much higher cost. As with the field review of the KGE assets, the severance issues are presented according to the asset function, beginning with the transmission system, followed by the sub-transmission system, and finally by the distribution system.

CASE 1

In our opinion, Case 1 could be the best case for the City and the customers of both the City and KGE. Case 1 is a simple concept, but may be difficult to achieve. Beginning with an electric system map with the City boundaries placed upon it, the substations that fall inside the boundaries would be identified. Those within the boundaries would be purchased by the City and those outside the boundaries would be retained by KGE.

Distribution feeders that cross from the City's service area into KGE's territory would be metered at the boundary, but operated by the City. KGE would retain their customers, however the feeder would be operated by the City. An arrangement would be needed to address who is responsible for the maintenance in the other utility's territory, and which utility handles service drops. Each utility will want to deal with their own customers in every way, therefore service drops should be handled by the serving utility, even if that feeder is operated by the other utility.

Conversely, feeders from KGE substations that cross into the City's territory would be operated by KGE, metered at the borders to determine the part of the load and losses that are attributed to the City, but with no physical severance. The City would relate to its customers on the feeder in every way, however, the line would be operated by KGE. KGE would relate to their own customers on the feeder. The major benefit to the Case 1 arrangement is its low cost, as few new facilities would be needed (except for meters at boundary crossings). In other words, the electric system would not be changed.

An estimate of the cost of these metering stations has not been made, however it is expected that the cost would be comparatively low. No determination of the actual costs of implementing Case 1 has been performed, however, it is believed to be less than Cases 2 or 3. It is recommended that this case be put forth in conversations with KGE and the KCC to determine its feasibility. KGE may agree to cooperate or the KCC may agree to order KGE to cooperate. KCC's motive may be to protect customers since this is believed to be the lowest cost option.

Cases 2 and 3 assume some level of ownership of subtransmission service by the City. It is possible to let KGE continue to provide all transmission and subtransmission, even to the extent of owning and operating subtransmission facilities within the City's substations.

In similar cases, it has been argued that utilities never serve customers for another utility. This was shown to be false, a specific example being Arizona Public Service ("APS") an investor owned utility and Salt River Project ("SRP") a municipally owned utility in the Phoenix metropolitan area.

In this example, APS serves customers of SRP in an area isolated within APS's territory. APS serves these customers on behalf of SRP. SRP bills them just as though they were an integral part of their system. When outages occur, the customer calls SRP who in turn calls APS to fix the problem. It is all transparent to the customer. SRP compensates APS for the service as well as the demand and energy.

Had this arrangement not been made, SRP would likely had to build redundant sub-transmission lines, a redundant substation and feeders deep in APS's territory. This approach has saved a significant amount of money for SRP and its customers and has worked well for 40-50 years.

A similar case could be crafted for the City, however it will take significant cooperation from KGE or KCC action to accomplish. We recommend Case 1 be tested for viability.

CASE 2 AND CASE 3

Although the severance issues are the same in both Cases 2 and 3, the cost differential is based on KGE's level of cooperation. Therefore, we have presented them together according to the asset function.

138 KV SUB-TRANSMISSION SYSTEM

For the transmission system, metering would be required at the substations where the City would take control of the transmission from KGE. For both Cases 2 and 3, there are seven locations that were identified to likely require metering. These locations are at the following substations: Evans, Gill, Chisholm, Stearman (two required), Weaver and El Paso.

A line between the Stearman and Boeing substations appears to be outside the City limits. It is assumed that in the Case 3 scenario, KGE would not allow the City to purchase this line. Therefore, in Case 3, it was assumed that the City would need to build a new 138 kV transmission line between these substations (although some alternative arrangement could be made).

Table 3-1, below, provides a summary of the cost estimate for transmission system severance for Case 2 and Case 3.

Table 3-1
CITY OF WICHITA
ESTIMATE OF SEVERANCE COSTS – TRANSMISSION

Description	Case 2 – Moderate Cooperation with KGE	Case 3 – Minimal Cooperation with KGE
Metering	$875,000	$875,000
Transmission Line	$0	$250,000
Total	$875,000	$1,125,000

69 KV SUBTRANSMISSION SYSTEM

For the 69 kV subtransmission system, metering similar to that described for the transmission system would be needed at substations and on poles at the points of severance. This would be done on any line or tap that crosses the City limits. In Case 2, the assumption of congenial transmission sharing arrangements with KGE would require additional costs for metering. However, the costs of additional metering would likely be offset by the costs of the additional subtransmission lines required for Case 3.

As a requirement for municipalization, it is likely that new 69 kV transmission lines would be needed where a single line supports substations both inside and outside of the City. Similar lines would also likely be required for new substation construction that would be included as part of the severance. In Case 3, additional lines would be required, since it was assumed that subtransmission facilities outside the City would not be acquired.

There would also be the need for new terminations in existing substations, where the new 69 kV lines would be constructed. Similar to the 69 kV transmission line severance, Case 3 would require additional construction.

A final severance issue identified for the 69 kV system is the inclusion of pole mounted disconnect switches where lines cross the City boundaries. This would be the preferred option since it provides for emergency ties to KGE; however, there could be a permanent break of the line at these locations. This would imply the need for other lines.

A summary of cost estimates for the subtransmission system severance for Cases 2 and 3 is provided in Table 3-2 below.

Table 3-2
CITY OF WICHITA
ESTIMATE OF SEVERANCE COSTS – SUBTRANSMISSION SYSTEM

Description	Case 2 – Moderate Cooperation with KGE	Case 3 – Minimal Cooperation with KGE
Metering	$600,000	$450,000
Subtransmission Lines	$900,000	$1,800,000
New Terminations	$60,000	$120,000
Pole Disconnect Switches	$250,000	$250,000
Total	$1,810,500	$2,620,000

DISTRIBUTION SYSTEM

For the distribution system severance, there may be the need for additional 69 kV or 138 kV to 12.5 kV distribution substations. These substations are required where the capacity from existing substations is exceeded and expansion is required. In addition, a new substation may be required for certain customers who are served from an existing substation that would not be owned by the City, but who are too far from a substation owned by the City.

Certain existing distribution substations would also need to be reconfigured as part of the severance. In Case 2, it was assumed that 13 substations would be reconfigured and one new substation would be built. For Case 3, it was assumed that 10 substations would be reconfigured and 4 new substations would be constructed. The requirements for new substations are expected to be a contested item associated with the severance issue. In order to determine the exact needs for reconfiguration and additional substations, detailed engineering studies of capacity, load flow and distribution configuration would be required.

If reconfiguration of existing distribution substations is required, separation of the existing facilities within each substation would be necessary. This would include rearranging existing transformers, switchgears and feeders. Separate metering and switchgear installation would also be required.

There would be the need for some primary pole metering for new feeds to serve industrial loads within the City. In Case 2, this would be handled with primary metering between KGE and the City. New facility construction required in Case 3 would reduce the need for this type of metering.

Similar to the subtransmission system, severance costs would need to be included for pole-mounted disconnect switches where lines cross the City boundaries. This would likely be the preferred option, although alternatively there could be a permanent break of the line at these locations.

Construction of new 3-phase overhead express feeders to reconnect severed loads to other parts of the system, or directly to a substation would likely be required. This requirement is the result of the distribution lines crossing the City boundaries at many points. However, most of these feeders are expected to be only 0.5 to 2 miles in length. Transfer billing, assumed for Case 2, would likely alleviate the need for some of these express feeders.

There may also be a requirement for construction of new 3-phase overhead distribution systems where a single line exists to serve loads both inside and outside the City limits. In this case, a new parallel line may be needed. In Case 3, it was assumed that new lines would be constructed where necessary. For Case 2, this requirement could likely be achieved with transfer billing arrangements.

There will likely be a need for construction of new 2-phase and single-phase distribution facilities to pick up individual loads or small clusters of load that is isolated after severance. Similar to the new 3-phase distribution construction, a transfer billing arrangement, as described in Case 2, would likely decrease the amount of severance costs for this issue. In Case 3, it was assumed that new line construction is required.

A final issue related to distribution system severance is the need for construction of underground distribution facilities. It is not anticipated that many new facilities will be required, since little underground construction crosses the City limits. These facilities would be necessary only where the construction of new overhead facilities are problematic. Once again, in the Case 2 scenario, the transfer billing arrangement could reduce the costs associated with this type of severance when compared to the new construction required in Case 3.

Table 3-3 provides a summary of estimate for the distribution system severance for both Case 2 and Case 3.

Table 3-3
CITY OF WICHITA
ESTIMATE OF SEVERANCE COSTS – DISTRIBUTION SYSTEM

Description	Case 2 – Moderate Cooperation with KGE	Case 3 – Minimal Cooperation with KGE
New Distribution Substations	$1,500,000	$6,000,000
Reconfigure Existing Substations	$1,950,000	$3,000,000
Primary Metering	$60,000	$40,000
Pole Disconnect Switches	$280,000	$280,000
Express Feeders	$1,500,000	$2,000,000
3-Phase Distribution	$3,150,000	$6,075,000
2-Phase and 1-Phase Distribution	$1,080,000	$2,070,000
Underground Distribution	$600,000	$1,200,000
Total	$10,120,000	$20,665,000

SUMMARY AND CONCLUSIONS

In developing the estimate of the severance required for the City's municipalization effort, Beck identified the actions that would likely be required. Although these actions may seem difficult, they are achievable. In addition, the estimated costs to perform this severance are reasonable, when compared to the overall cost of acquisition of the KGE distribution facilities in the City (as described in Section 3). Based on the comments and efforts addressed above, Table 3-4 below provides a summary of the estimated cost of physical severance associated with the KGE facilities in the City.

Table 3-4
CITY OF WICHITA
SUMMARY ESTIMATE OF SEVERANCE COSTS

Description	Case 2 – Moderate Cooperation with KGE	Case 3 – Minimal Cooperation with KGE
Subtransmission System 138kV	$875,000	$1,125,000
Subtransmission System 69kV	$1,810,000	$2,620,000
Distribution System	$10,120,000	$20,665,000
Subtotal – Direct	$12,805,000	$24,410,000
Engineering (15%)	$1,920,750	$3,661,500
Construction Management (10%)	$1,280,500	$2,441,000
Subtotal – Direct & Indirect	$16,006,250	$30,512,500
Contingency (20%)	$3,201,250	$6,102,500
Total	$19,207,500	$36,615,000

The estimated cost of physical severance for the City is between $19.2 million and $36.6 million, depending on the level of cooperation provided by KGE. As a conservative approach for our feasibility study, the high end of the range of severance estimates, $36.6 million has been utilized as the cost of severance in the pro forma analysis. However, as mentioned earlier, it is recommended that the City approach KGE or KCC with the lower cost implementation of the Case 1 scenario.

INTRODUCTION

The purpose of this section is to provide a summary description of the functional requirements, resource requirements, governance and management of a municipally-owned and operated electric utility. The information presented here is educational and not intended to communicate how the City of Wichita should organize and operate an electric utility, if the City's leaders decide to municipalize the electric utility system.

FUNCTIONAL REQUIREMENTS

The function of an electric utility is to produce or otherwise acquire electrical energy and deliver that energy, on demand, to end-use customers. Customers value the electricity they receive because it can be readily converted to other forms of energy that are useful for a wide variety of purposes. The most common uses are for lighting, space heating and cooling, industrial processes, communication signals, and the operation of appliances, computers and other types of business equipment.

The delivery of value to end-use customers involves several important processes. Before electricity can be produced, a utility must secure a supply of raw energy in the form of fossil fuel, uranium, water, sun or wind. The utility then converts the raw energy to electrical energy through the process known as electric production (usually generation). Once produced, the utility uses a network of high voltage transmission lines and lower voltage distribution lines to move the energy to its points of use. Finally, the electric utility measures the use of electricity by a customer and charges the customer for the electricity and related services.

Historically, electric utilities in the U.S. have been vertically-integrated, where a single utility, operating in a defined geographic area, provides all the functions just described. It does this either by owning and operating the entire infrastructure needed to deliver the end-use services or by purchasing some of those services from others. For example, a local distribution company typically purchases all of the electricity needed by its customers from one or more wholesale generators and contracts for the delivery of the electricity to its distribution system over transmission lines that are owned by others. KGE, a vertically-integrated electric utility, provides service to customers in and around the City using an infrastructure (generation, transmission, distribution and customer service) that it owns and operates under the regulatory authority of the KCC. Because KGE operates as a monopoly, the Commission regulates conditions of service, quality of service and price in lieu of competition.

At the present time, the electric utility industry in the U.S. is being transformed by federal and state "deregulation" (re-regulation) and by increasingly competitive wholesale and retail markets for electricity. Although the Kansas state legislature has not yet passed electric restructuring legislation, the structure of the new industry is increasingly clear. The most important change is that the vertically-integrated electric utility is being replaced by up to four separate entities, each of which performs one or more of the key utility functions described earlier.

Generating Companies – secure raw energy supplies, convert the raw energy to electricity, and deliver it to the transmission network.

Transmission Companies – receive the electric energy from the generating companies and move it in large quantities, over relatively long distances to major delivery points.

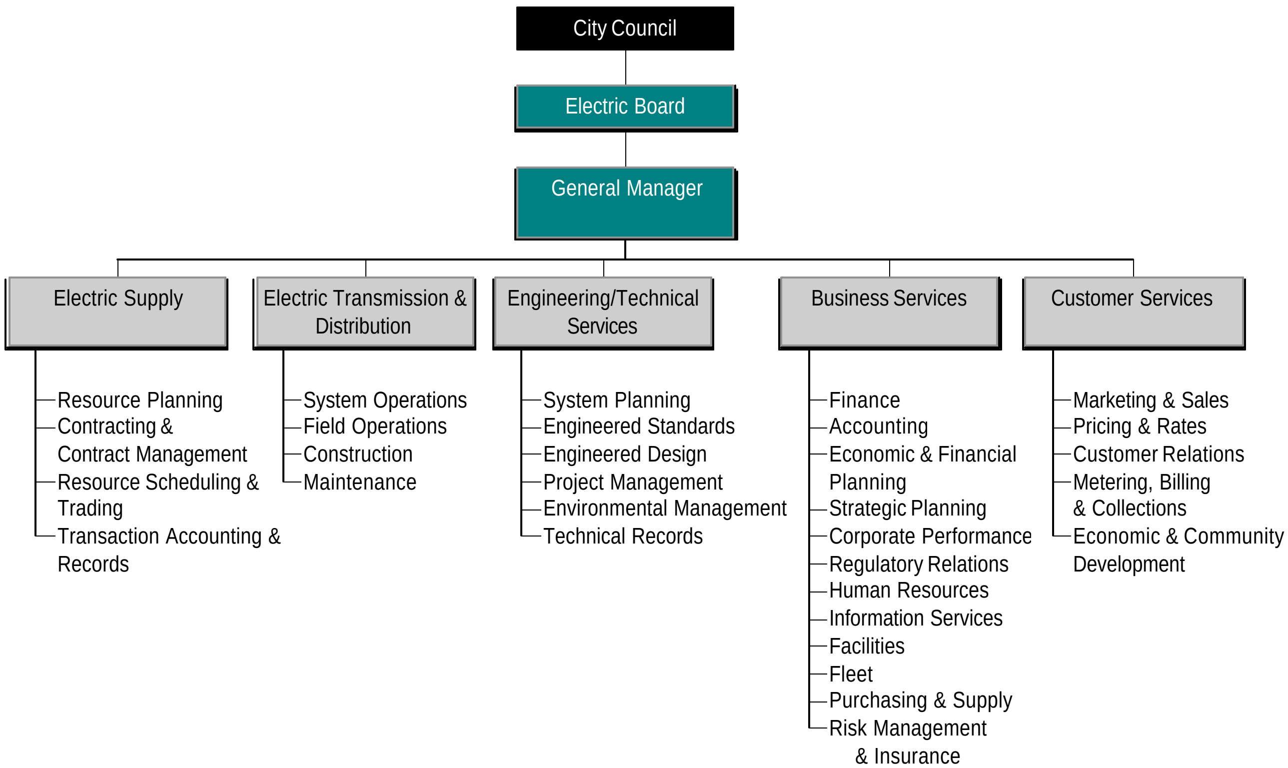
Distribution Companies – receive the electric energy at these delivery points and move it over a lower voltage network of lines to the end-use customers. Depending on the legislation in a particular state, the distribution company may or may not be permitted to handle customer metering and billing.

Retail Service Providers – are new entities whose function is to match up the needs of retail end-use customers with suppliers of all the resources (generation, transmission and distribution) needed to make the delivery.

For purposes of this report, Beck has assumed that the City will acquire the facilities needed for it to operate a non-generating, but otherwise full-service, vertically-integrated electric utility. While the City would not own or operate its own generating plants, it would engage in the generation business on behalf of its retail customers by contracting with one or more generating companies. In all of the states that have begun to implement electric utility restructuring and re-regulation, municipal electric utilities have been recognized as unique. For the most part, they have been permitted to continue performing all of the functions of a vertically-integrated utility with minimal state regulation. Except in a few states, municipal utilities have traditionally regulated their own operation through elected or appointed governing bodies (i.e. city councils and/or utility boards). Regulated investor-owned utilities like KGE, on the other hand, have been required to "unbundle" their generation, transmission and distribution, and retail sales functions into separate businesses to help ensure the creation of truly competitive wholesale and retail markets for electricity.

Beck has also assumed that the City's electric utility will comprise three ***core functions***: (1) electric supply, (2) electric transmission and distribution, and (3) customer services. Additionally, the utility will require engineering/technical and business services in support of the core functions. The following Figure 4-1, provides an organization chart which depicts a functional structure that is typical of many municipal electric utilities.

Figure 4-1



Following is a brief description of each of the functional areas shown in the chart:

Electric Supply. This area includes the forecasting of customer requirements for electricity and the development of both short and long-range plans for securing the resources needed to meet those customer requirements. The supply function also includes resource contracting and contracts management, resource scheduling and trading, purchase/sale transaction accounting and records management.

Transmission and Distribution. The "wires" part of the business includes all functions involved in the construction, operation, and maintenance of transmission, substation, distribution and metering facilities. Included are facility extensions, upgrades and replacements occasioned by customer growth, new technologies and the aging of plant facilities. Operation and maintenance also includes planning for and responding to problems caused by weather, tree growth, animals, equipment failures and other factors that damage facilities or disrupt customer service.

Customer Service. This area includes end-use marketing and sales, pricing of services and all other aspects of customer relations. It also includes metering of retail electric use, billing for services delivered and collection of revenues. This area often includes functions related to economic and community development that are logically supported by the electric utility.

Engineering/Technical Services. This area includes planning, design, and the technical aspects of regulatory compliance and records management for the transmission and distribution infrastructure.

Business Services. This area includes all other support functions required to operate the electric utility enterprise. Included are finance and accounting, business planning and performance, human resource management, information services, purchasing and supply, general facilities and fleet management, risk management and regulatory management.

Although, the municipal electric utility has been described as a vertically-integrated, functionally-organized entity, the new structure of the industry makes it desirable for municipalities to emulate the "unbundled" structure of their privately-owned competitors. Even if not required by law, municipal utilities are beginning to report revenues and costs as if they were comprised of separate generation, wires and customer service businesses. Some have even re-organized along those business lines in order to understand and improve their competitive position.

RESOURCE REQUIREMENTS

Performance of the electric utility functions just described requires substantial human and capital resources. Nearly all of these resources can be acquired by contract; however, municipalities typically hire their own employees and acquire the general facilities needed to effectively perform most routine functions. Indeed, one of the benefits of municipal ownership of the electric utility is the contribution that such an enterprise can make to the economy through local employment and purchase of goods and services. Local control of the utility operation is another important benefit. In theory, a well-written and well-managed contract for services can retain this control. In actual practice, such control is always difficult to achieve. Contract services are most often used by municipalities to handle non-recurring or infrequent functions, to augment internal resources during periods of heavy workload, or to obtain access to technologies, specialized equipment and other capabilities that are not economical to develop and sustain internally. Municipal utilities frequently use contract electric line crews (sometimes on a continuous basis) for major construction projects (substations and lines), recurring construction and routine maintenance (especially tree trimming, pole inspections and substation equipment). Contracts are increasingly used today for information management and customer services such as accounting, billing and call center operations.

Assuming that the City follows the prevailing practice of most municipal electric utilities and does not own or operate its own generating plants, its organization would likely include from 500 to 800 employees. The size of the workforce would be near the upper end of this range if the electric utility is a stand-alone entity (one that does not rely on other city departments for support services) that selectively contracts for outside services as described above.

Given the size of the City's proposed electric service area, the utility would probably operate out of two or three locations. In order to provide prompt response to customer and system requirements, line crews, along with most engineering and customer contact employees should be housed in multi-purpose "service centers" that are strategically located to minimize operating costs and travel time. Each service center would support office functions, crew and other "field" functions (with requisite vehicles and equipment), and materials inventory (inside and outside storage). Corporate functions, including executive management, electric supply and business services could be housed at an "office only" facility or at one of the service centers. Certain other operating functions such as system control, crew dispatch and vehicle maintenance would best be housed at one of the service centers and not duplicated at multiple locations.

MUNICIPAL UTILITY GOVERNANCE

The success of a municipal electric utility in today's fast-changing and increasingly competitive business environment is largely a function of its governance. The form of governance is typically established by some combination of state law, local charter and local ordinance. The execution of governance is entirely the responsibility of the City's elected and appointed representatives. The American Public Power Association ("APPA") in its ***Handbook for Public Power Policymakers*** states that the members of a local governing board must serve four primary roles:

1. **Trustee** – ensuring that policymaking and management is carried out in the long-term best interests of the utility and the community. This includes protecting and judiciously using the utility's assets.
2. **Representative** – representing the interests of the utility's owners, who are the customers.
3. **Regulator** – performing regulatory functions that are assigned by law or practice. This usually includes approval of budgets, rates and charges, and issuance of debt.
4. **Activist** – staying current with the electric utility industry and community needs; actively participating in the development of business strategy and the monitoring of business results.

Municipal electric utilities in the U.S. operate under a variety of governance structures. These include:

1. **Independent Board or Commission.** Accountable directly to the customer/owners. The board members can be appointed by a mayor or city

council, elected by the customer/owners, or appointed by other board members.

2. **Semi-Independent or Advisory Board or Commission.** Accountable or advisory to a city council. Board members are usually appointed by a mayor or city council.

3. **City Council**. No separate board or commission. In some cases, the council members convene in separate meetings (not regular council meetings) for utility business, usually following practices that are different from those used to handle the functions of general government.

The structure of governance itself has less impact on the success of a municipal utility than the actions of the governing board and its relationship with management. What is most critical today is a governing board comprised of competent people who understand what it takes to run a business, are able to focus their attention on the needs of the electric utility, and are willing to make difficult business decisions without undue consideration of political factors.

STRANDED INVESTMENT QUANTIFICATION

As discussed in Section 1 of this report, the municipalization effort initiated by the City may impose stranded investments on KGE. KGE has determined that the cost of these stranded investments could be as high at $1.63 billion, depending on the revenue associated with the distribution systems. However, it is the opinion of Beck that this value is grossly exaggerated, for the following reasons:

- It assumes market prices are much lower over time than reasonable market price forecasts.
- It does not account for distribution system revenues, as required by FERC.
- No consideration is given to the time value of money, as required by FERC.

This section provides a description of the KGE's and Beck's approaches to the calculation of the stranded investment costs. It is the opinion of Beck that the stranded cost value may be approximately $145 million. As noted previously, a FERC judge will likely ultimately decide the issue of stranded costs. The City may argue that no stranded costs exist in this situation. Therefore, Beck's opinion should be considered a conservative approach to this issue.

STRANDED COST CALCULATION

FERC's Order No. 888, in addition to its Opinion No. 438 in the City of Las Cruces v. El Paso Electric Company, has issued an approach to determining stranded investments that is summarized as follows:

SCO = (RSE – CMVE) x L

Where:

SCO = Departing Customers Stranded Cost Obligation

RSE = Revenue Stream Estimate that the utility could have expected to recover from the departing customer if open access transmission had not been available

CMVE = Competitive Market Value Estimate of the capacity and associated energy released by the departing customer

L = Length of time the utility could have reasonably expected to continue to serve the departing customer if open access had not been available.

The terms incorporated above are open to interpretation and quantification. Therefore the SCO would ultimately need to be determined through a stranded cost proceeding. The analysis following develops a stranded cost estimate which is believed to be generally consistent with FERC precedent.

KGE APPROACH

A brief review of KGE's determination of stranded investment is provided below. A detailed response by KGE to the City's request is provided as Appendix A of this report.

KGE's summary of the stranded cost charge is provided in Table 5-1 below:

Table 5-1
ANNUAL STRANDED COSTS AND MONTHLY STRANDED COST CHARGE
2002-2015

Year	Average Monthly RSE	Average Monthly CMVE	Monthly Stranded Cost Charge	Annual Stranded Cost Charge
2002[1]	$28,058,454	$16,710,860	$11,347,594	$113,475,940
2003	$28,058,454	$16,710,860	$11,347,594	$136,171,128
2004	$28,058,454	$16,710,860	$11,347,594	$136,171,128
2005	$28,058,454	$17,011,656	$11,046,798	$132,561,576
2006	$28,058,454	$17,317,866	$10,740,588	$128,887,056
2007	$28,058,454	$17,629,587	$10,428,867	$125,146,404
2008	$28,058,454	$17,946,920	$10,111,534	$121,338,408
2009	$28,058,454	$18,269,964	$9,788,490	$117,461,880
2010	$28,058,454	$18,598,824	$9,459,630	$113,515,560
2011	$28,058,454	$18,933,602	$9,124,852	$109,498,224
2012	$28,058,454	$19,274,407	$8,784,047	$105,408,564
2013	$28,058,454	$19,621,347	$8,437,107	$101,245,284
2014	$28,058,454	$19,974,531	$8,083,923	$97,007,076
2015	$28,058,454	$20,334,072	$7,724,382	$92,692,584
Total Stranded Cost Charge				**$1,630,580,812**

1 Ten months, per Wichita's request.

The first observation of the total stranded cost charge above is that each year values have been added to calculate this total, which ignores the financial principle of the time value of money (i.e. a dollar now is worth more than a dollar in 15 years). FERC has agreed with this assertion in its Order 888b, which indicates that a net present value ("NPV") should be applied to future revenue streams, although the discount rate used to calculate the NPV is subject to determination based upon the specific situation being examined.

KGE has determined that the "L" component of the stranded cost calculation should be approximately 13 years (year 2002 begins in March). The basis for this determination is a historical obligation for KGE to serve the City of Wichita.

KGE's RSE calculation is based on the total revenue billed in 1999 to the Wichita area customers, which they have determined to be approximately $354 million. KGE agrees that the total revenue billed value needs to be reduced by the amount of transmission revenues that KGE would continue to receive from the municipal utility, as well as the distribution system related revenues. However, KGE did not reduce the total revenue billed by the distribution system related revenues because the City had not provided details on how it would establish such a system. KGE's adjustment for anticipated transmission revenues is based on the Open Access Transmission Tariff, which requires monthly energy and coincident peak demand data for the Wichita area load and monthly coincident peak demand data for the transmission system. KGE has estimated that the transmission related revenue for 1999 was approximately $17 million. Subtracting the $17 million from the $354 million yields approximately $337 million. Dividing this value by 12 months yields a monthly RSE value of approximately $28 million (without reductions for distribution revenue, as noted above).

KGE's CMVE calculation is based on its determination of the market value of released capacity and associated energy and the annual load of the Wichita area during 1999. The annual load for Wichita during 1999 provided by KGE was 5,832,761 MWh. KGE's approach to determining the market value for power is based on the long run equilibrium price of released capacity and associated energy, which they believe results in an annual average of $34.38/MWh. This price was derived from published measures of spot market prices for energy during on-peak and off-peak periods and the cost of building and operating a combustion turbine generation unit. They have assumed a natural gas price of $2.82/MCF (Million Cubic Feet) and a heat rate of 10,857 Btu/kWh. They have assumed that the annual average market value of power above ($34.38/MWh) applies to the period through December 31, 2004, after which it will increase by 1.8 percent per year. By multiplying the price for power time that annual load for the Wichita area, and dividing by 12 months, KGE determined the average monthly CMVE.

The difference between the RSE and the CMVE is calculated as the monthly stranded costs charge. This charge is multiplied by 12 months to determine the annual stranded cost charge, as presented in the table above.

R.W. BECK CALCULATION

Beck's calculation of the stranded cost estimate follows the formula presented above and generally the same approach as outlined by KGE. However, there are differences in the two approaches that result in a widely different stranded cost determination. Beck's summary of its estimation of stranded costs is provided in Table 5-2 below.

Table 5-2
R. W. BECK STRANDED COST CALCULATION

Year	Avg Monthly Op Rev	Less Transmission	Less Distribution	Monthly RSE	Calculated CMVE	Monthly Stranded Costs	Annual Stranded Costs
2002	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$16,692,391	$4,050,608	$40,506,080
2003	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$17,318,767	$3,424,232	$41,090,789
2004	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$17,318,767	$3,424,232	$41,090,789
2005	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$18,174,991	$2,568,008	$30,816,093
2006	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$19,219,761	$1,523,238	$18,278,852
2007	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$19,852,181	$890,818	$10,689,821
2008	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$21,057,562	($314,562)	$0
2009	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$21,725,120	($982,121)	$0
2010	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$22,408,298	($1,665,299)	$0
2011	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$23,094,673	($2,351,674)	$0
2012	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$23,728,893	($2,985,894)	$0
2013	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$24,540,888	($3,797,889)	$0
2014	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$25,154,410	($4,411,411)	$0
2015	$29,645,811	$2,674,044	$6,228,768	$20,742,999	$25,731,704	($4,988,705)	$0
Total NPV							$145,332,533
Discount Rate							8.5%

Within this conservative determination of potential stranded costs, Beck has utilized the same period of time for the "L" as KGE. (This calculation of "L" is subject to legal review and this conservative approach to determine this value does not imply that the City is in agreement with this value.)

As can be observed above, Beck's determination of monthly stranded costs becomes negative after 2007, therefore, the ultimate determination of the "L" value may not have a significant impact on the overall calculation of stranded costs for this situation. Another immediate observation from Table 5-2 is the application of the net present value to the projected revenue streams. For the purposes of this draft assessment, Beck has utilized a discount rate of 8.5 percent, which is consistent with the lending rate used in the financial pro forma projections for the City.

Beck's calculation of the RSE value is the difference between the average monthly operating revenue, less transmission revenue and distribution revenue. The annual operating revenue utilized was approximately $356 million (according to KGE's KCC filed data). Dividing this amount by 12 months results in an average monthly operating revenue value of approximately $29.6 million. Annual transmission revenues were determined from Beck's cost of service study and estimated at approximately $32 million for 1999 (this is the "revenue requirement" for the transmission function of KGE). Dividing this value by 12 months results in the approximately $2.6 million value presented above. Annual distribution revenues were determined from revenue requirements for KGE and estimated at approximately $93 million for 1999 (this is the revenue requirement for the distribution function of KGE). Dividing this value by 12 months results in the approximately $6.2 million value presented above. Subtracting the transmission and distribution revenues from the average monthly operating revenue results in a monthly RSE value of approximately $20.7 million.

Becks' calculation of the CMVE is based on the total retail load for the Wichita area (5,635,666 KWh as presented in the KCC filing data) multiplied by the estimate for the price of power within the SPP region. Beck's estimate for the price of power is based on the results of the market price forecast contained in Section 6 of this report. Beck's estimate for the price of "all-in" power (i.e. released capacity and associated energy) is presented in Table 5-3 below:

Table 5-3
PRICE FOR POWER

Year	($/MWh)
2002	$ 35.43
2003	$ 36.76
2004	$ 38.58
2005	$ 40.79
2006	$ 42.14
2007	$ 44.70
2008	$ 46.11
2009	$ 47.56
2010	$ 49.02
2011	$ 50.36
2012	$ 52.09
2013	$ 53.39
2014	$ 54.62
2015	$ 55.76

The difference in the monthly RSE and the monthly CMVE (the annual load divided by 12 months multiplied by the price for power above) represents the monthly stranded cost calculation. Because Becks' determination of the RSE is lower than KGE's (primarily due to the revenue associated with the distribution system) and because Beck's calculation of CMVE increases at a rate faster than KGE's calculation (primarily due to the higher cost of power projected by Beck), the resulting monthly stranded costs becomes negative beginning in the year 2008. A legal interpretation of the significance of the negative stranded investment values (i.e. stranded benefit) has not been conducted, therefore, these negative values have not been applied to the revenue stream calculations. For the purposes of this assessment, these future revenue streams are assumed to be zero. The resulting estimation of the net present value of the stranded costs is determined to be approximately $145 million. This value is incorporated into the pro forma analysis as the amount required by the City to compensate KGE for its stranded investment. Again, this is a conservative estimate and does not imply that stranded costs necessarily exist for this situation.

POWER MARKET ASSESSMENT

The market price of electricity is an essential input to the determination of the economic impact associated with municipalization. Beck estimated these inputs using the *Prosym™* model, an hourly chronological economic dispatch and production cost model. The majority of the inputs (variable cost data concerning all units in SPP) to this model were obtained from Henwood, Inc. ("Henwood"), and were reviewed by Beck. The primary study period for the electric market analysis is from 2001 to 2022 and is divided into two distinct periods.

Over the initial 10-year period, a detailed computer simulation was developed to model KGE's market-based dispatch and operations within SPP. Over the last portion of the study period, the electric market is expected to become more fluid and responsive to general economic trends and underlying market forces and it is anticipated that reasonable projections of economic conditions can provide a reliable forecast of market prices. During this latter period, market-based prices are assumed to be heavily influenced by the full-cost recovery of the most efficient, low-cost new market entrant generating technologies. As such, market prices over the latter portion of the study period are based on the detailed market prices modeled over the initial 10 years, with projections based on the assumed escalation of capital, operating costs, and fuel prices for the least-cost new market entrant generating technologies.

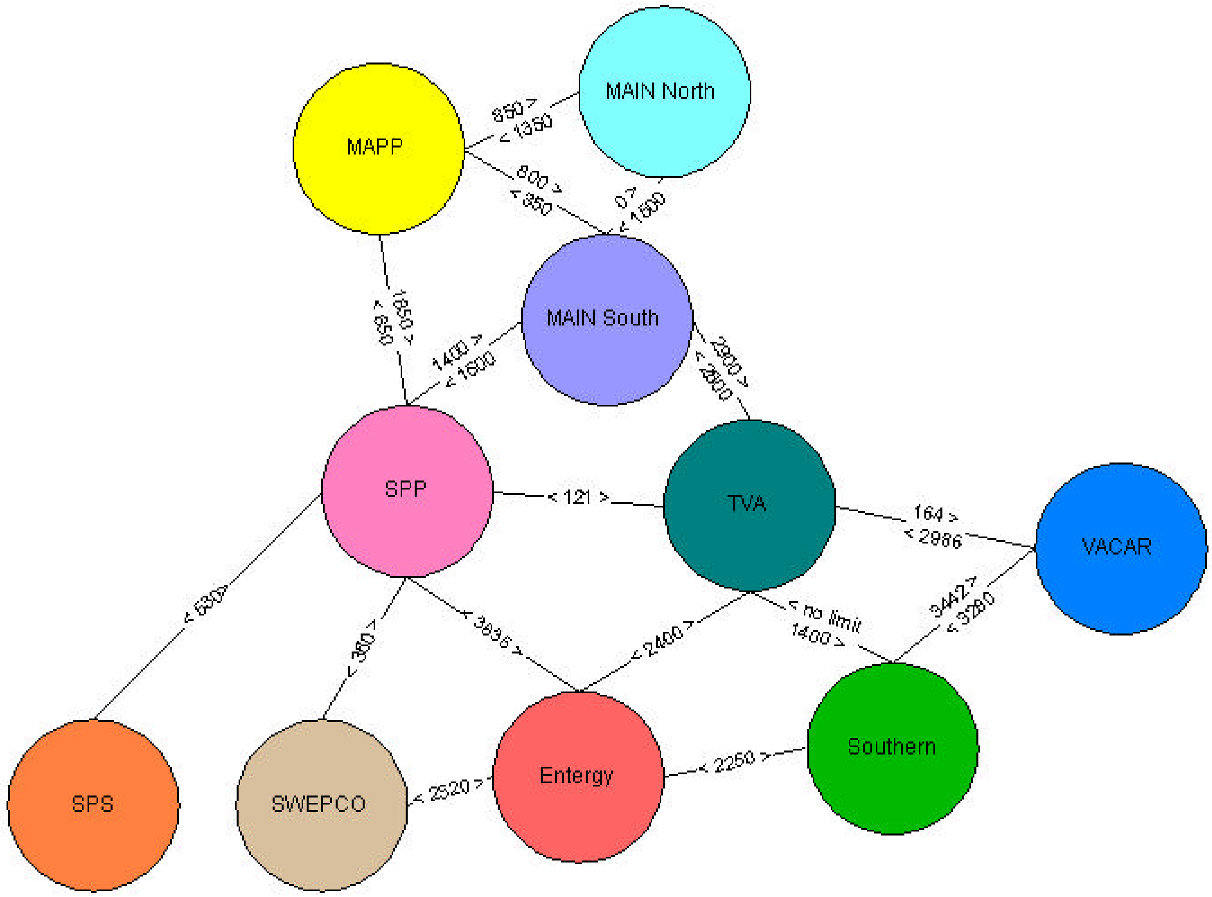
The results of the market price assessment include average market price information for each year, as well as annual price profiles for the energy market and specific outputs detailing the projected energy output and operating cost of KGE's assets. These specific outputs are utilized in Section 7 to determine the revenue requirements for KGE and the economic impact of municipalization.

METHODOLOGY AND ASSUMPTIONS – INITIAL PERIOD

The initial period energy prices have been prepared using *Prosym™*, which is an hourly chronological economic dispatch and production cost model. Beck has modeled the entire SPP Market Area region, and interconnecting regions, on a simultaneous basis. In this analysis, SPP area units are economically dispatched to serve SPP area load or other market areas' load. Correspondingly, units located in other market areas can be dispatched to serve SPP area load.

- For the multi-region model, it was necessary to include twelve separate market areas. These areas are defined according to transmission constraints and traditional North American Electric Reliability Council ("NERC") sub-regions. Figure 6-1 represents the market areas and how they are interconnected.

Figure 6-1



Market Areas Defined in the Model

Entergy includes Arkansas Electric Coop., Central Louisiana Electric Co., Entergy Corp., Louisiana Power & Light and others.

MAIN North includes Wisconsin Upper Michigan Subregion, Wisconsin Power & Light Co., Upper Peninsula Power Co. and others.

MAIN South includes Commonwealth Edison Co., East Missouri Subregion, Union Electric Co., Central Illinois Light Co., Central Illinois Public Service, Illinois Power-Soyland Power Pool, Springfield, Illinois-City Water Light & Power and others.

MAPP includes Mid American Resources, Nebraska Public Power District, Omaha Public Power District, Northern States Power, Minnesota Power, Otter Tail Power, Manitoba Hydro, Saskatchewan Power and others.

Southern includes Alabama Electric Coop., Alabama Power, Georgia Power, Gulf Power, Mississippi Power and others.

SPP includes Associated Electric Coop., City of Springfield, Empire District Electric, Grand River Dam, Kansas City Power & Light, Kansas Gas & Electric, Kansas Power & Light, Midwest Energy, Missouri Public Service, Oklahoma Gas & Electric, Public Service Co. of Oklahoma, Southwestern Power Administration, Sunflower Electric Power, Western Farmers Coop., WestPlains Energy and others.

SPS includes Southwestern Public Service Co.

SWEPCO includes Northeast Texas Electric Coop. and Southwestern Electric Power Co.

TVA includes Tennessee Valley Authority, City of Chattanooga, and Tapoco, Inc.

VACAR includes Carolina Power & Light, Duke Power Co., Nantahala Power & Light, Old Dominion Electric Coop., Santee Cooper, South Carolina Electric & Gas, and Virginia Power Co.

We assumed a bilateral marketplace (where power is traded directly between entities, as opposed to a power pool) exists within SPP for the entire study period and developed the energy market clearing price (and the corresponding energy related revenues) based on a marginal economic dispatch of the system. Beck's model is an economic cost-based model; for every hour the system is dispatched to exactly meet load while incurring the least possible cost.

The following summarizes the major assumptions used in this analysis:

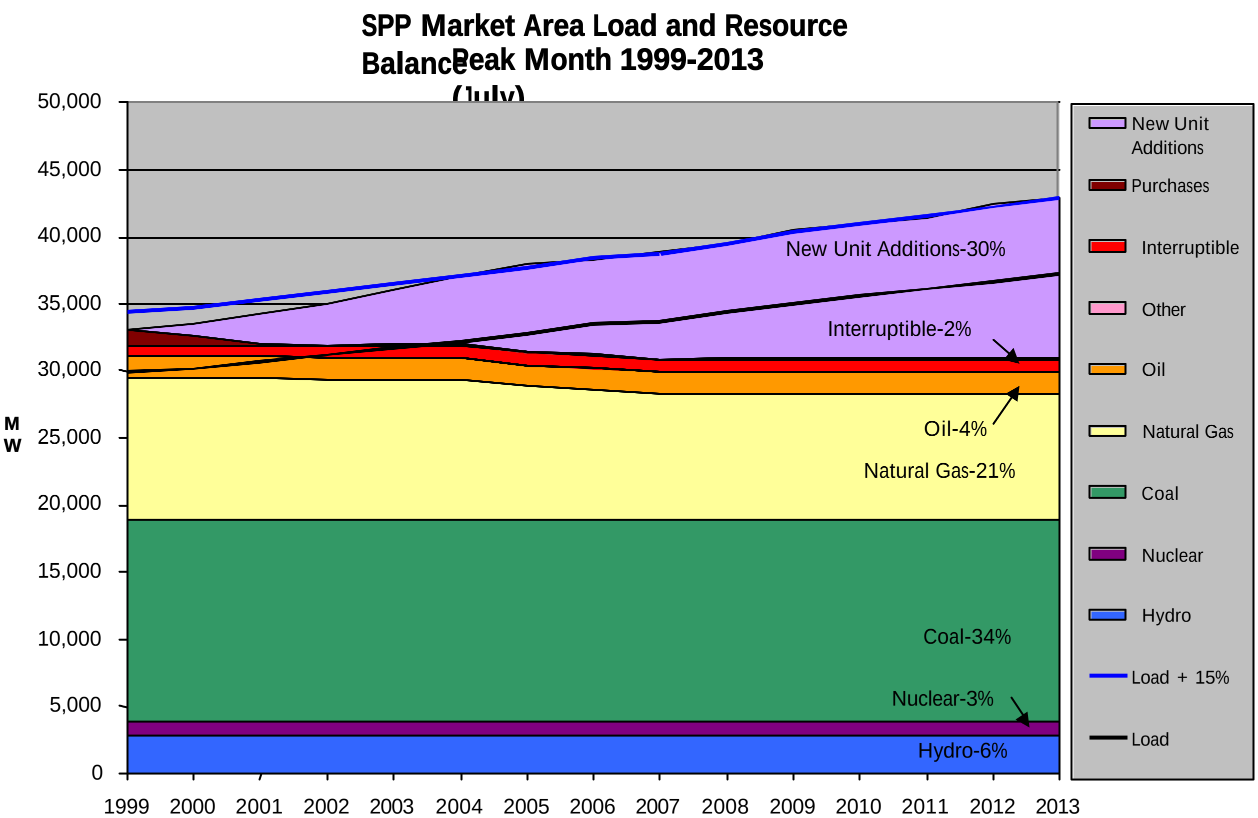
- For the most part, each market area's load growth is based on publicly available FERC Form 714's or Energy Information Agency ("EIA") 411 data submitted by individual utilities. Load information for smaller utilities and utilities that do not provide public data may be estimated. Loads for the SPP market area have been updated based on the latest SPP EIA 411 dated April 1, 2000. Total peak load for the SPP Market Area in summer of 2000 is 30,160 MW (This does not include SPS and SWEPCO portions of SPP). From years 2000 to 2013, peak load for this defined market area grows at an average rate of 1.58 percent per year.
- Inflation is assumed to be 2.4 percent in 2000, 2.6 percent in 2001 and 2002, and 2.5 percent each year thereafter. These numbers are based on blue chip economic indicators published by the U.S. Department of Commerce.
- SPP Market Area new resource additions are summarized in the following table:

Table 6-1
NEW UNIT ADDITIONS

Unit Name	Developer	Online Date	Max Capacity (MW)	Full Load Heat Rate	VOM Cost (Yr 2000 $/MWh)
CC.SPP.2003	Generic	1/1/03	2 x 500	6,940	2.5
CC.SPP.2003	Generic	1/1/04	2 x 500	6,940	2.5
CC.SPP.2003	Generic	1/1/05	3 x 500	6,940	2.5
CC.SPP.2003	Generic	1/1/06	500	6,940	2.5
CC.SPP.2003	Generic	1/1/07	2 x 500	6,940	2.5
CC.SPP.2008	Generic	1/1/08	500	6,730	2.5
CC.SPP.2008	Generic	1/1/09	2 x 500	6,730	2.5
CC.SPP.2008	Generic	1/1/10	500	6,730	2.5
CC.SPP.2008	Generic	1/1/11	500	6,730	2.5
CC.SPP.2008	Generic	1/1/12	2 x 500	6,730	2.5
CC.SPP.2008	Generic	1/1/13	500	6,730	2.5
CC.SPP.1998	Generic	1/1/00	4 x 170	11,000	2.5
CC.SPP.1998	Generic	1/1/01	6 x 170	11,000	2.5
CC.SPP.1998	Generic	1/1/02	4 x 170	11,000	2.5
Gordon Evans EC3	Western Resources	1/1/00	200 (300 in 2001)	10,163	2.5
St. Francis 2	Associated Electric Coop.	6/1/01	255	11,000	2.5

- New generic combined cycle and simple cycle generation units are assumed to be added to the SPP market beginning in year 2001 to maintain an overall reserve margin for SPP of approximately 15 percent.
- Generally, generic unit efficiencies are based on a full-load heat rate of 7,030 to 6,730 Btu/kWh for generic combined cycle units, depending on year added, location and technology type (F, G, or H). For generic combustion turbine units, full-load heat rates are between 11,000 to 10,200 Btu/kWh, depending on year added. We add units to meet the targeted reserve margin assuming new combined cycle units will generally be around 500 MW and combustion turbines will be around 170 MW.
- The following chart is a preliminary load and resource balance of the SPP Market Area, although subject to further revisions, it provides a good indication of the resource mix and levels of reserve.

Figure 6-2



Note: Resource percentages are based on resource mix in the SPP market area in year 2013 (does not include SPS and SWEPCO).

- Unserved energy and interruptible load is priced at $200 per MWh in 2000, escalating at inflation. Even though the cost of turning off interruptible customers is sometimes close to or even $0 per MWh, we believe that our pricing should reflect the reluctance of utilities to turn off interruptible customers. Interruptible load is dispatched as a last resort for meeting demand. The price given for unserved energy here is a proxy, unserved energy should not occur in the model.

- The majority of units are committed and dispatched economically, meaning they are committed and dispatched only when they are the next least expensive unit needed to meet the next increment of load. However, units that have been historically considered "must-run", i.e. hydro and nuclear (some coal), are committed and dispatched based on these historical premises. These base-load units are modeled to turn on first in the dispatch stack and usually run as much as they can, or at the times when it is appropriate for them to run. This exception to the economic commitment and dispatch of units rarely affects the market clearing prices developed in an area, as it is usually not a must-run unit that sets the market clearing price, but a higher-priced unit free of these operating restrictions.

The following fuel price assumptions are used for the original case:

- Annual average natural gas prices for each region modeled are based on R. W. Beck assumptions developed from WEFA, Inc. forecasts. The following tables represent the gas prices used in the model (Table 6-2 and 6-3). The total natural gas price for any particular plant is the basin price plus the appropriate regional transportation charge. It should be noted that most recent natural gas markets are considerably higher than those presented in this report. This has generally resulted in higher electricity prices. The impact of these higher electricity prices has not been quantified for this report. However, the values utilized in this report can be considered conservative in light of recent higher natural gas prices. Coal price escalation values utilized for this study are presented in Table 6-4.

Table 6-2
NATURAL GAS BASIN PRICE
(Year 2000 Dollars per MMBtu)

Year	Base Case
2000	$ 2.57
2001	$ 2.51
2002	$ 2.47
2003	$ 2.46
2004	$ 2.47
2005	$ 2.47
2006	$ 2.54
2007	$ 2.60
2008	$ 2.66
2009	$ 2.72
2010	$ 2.79
2011	$ 2.80
2012	$ 2.82
2013	$ 2.83

Table 6-3 FORECASTED NATURAL GAS TRANSPORTATION CHARGES	
Natural Gas Region	**(Year 2000 Dollars per MMBtu)**
Alabama & Georgia	0.67 - .86
MAIN (1)	0.30
MAPP (2)	0.85
Mississippi Delta (3)	0.19
Mississippi Valley (4)	0.27
SPP (5)	0.29
TVA (6)	0.27
VACAR (7)	0.84 - 1.57

(1) Mid-America Interconnected Network (mostly Illinois, Wisconsin).
(2) Mid-Continental Area Power Pool (mostly Nebraska, North and South Dakota, Minnesota).
(3) Mississippi Delta region comprises East Texas, Louisiana, Southern Mississippi.
(4) Mississippi Valley is Western Tennessee, Eastern Arkansas and Northern Mississippi.
(5) SPP region comprises Kansas, Oklahoma, Missouri and Western Arkansas.
(6) Tennessee Valley Authority.
(7) Virginia/Carolina's Subregion.

- A high fuel price sensitivity was based on gas prices 50 cents higher than the original case for all years of the study ($3.36 per MMBtu in 2000).
- A low fuel price sensitivity was based on gas prices 50 cents lower than the original case for all years of the study ($2.36 per MMBtu in 2000).
- For all cases, coal prices are based on historical information for each plant and nominal prices are de-escalated below inflation (prices increase at less than inflation).

Table 6-4 COAL ESCALATION			
Year	**Coal Escalation**	**Inflation**	**Total Escalation**
2000	-1.30%	2.40%	1.07%
2001	0.00%	2.60%	2.60%
2002	-0.60%	2.60%	1.98%
2003	-1.50%	2.50%	0.96%
2004	-0.40%	2.50%	2.09%
2005	-1.00%	2.50%	1.47%
2006	-1.00%	2.50%	1.47%
2007	-1.00%	2.50%	1.47%
2008	-1.00%	2.50%	1.47%
2009	-1.00%	2.50%	1.47%
2010	-1.00%	2.50%	1.47%
Average	**-0.89%**	**2.51%**	**1.60%**

EXTENDED ANALYSIS

Estimates of the potential costs of the KGE generating units have been provided in this extended analysis. In the extended analysis, market clearing prices for the period 2013 to 2017 were interpolated using the *Prosym™* market clearing price for 2012 (adjusted for inflation) and the cost of the new units that were assumed to be at the margin during on-peak and off-peak hours. The extended analysis includes the base case and both the high and low case fuel sensitivities. Unit data for the period 2001 through 2022 has been calculated based on the results of the *Prosym™* analysis for the year 2012 and the following assumptions:

- Load growth for the KGE region continues to be approximately 2.6 percent per year from 2013 to 2022.
- Capacity prices are assumed to escalate at inflation after 2012.
- No further improvements in unit heat rate efficiency from 2013 to 2022.
- New gas-fired generators will be the type of units added to meet growth in demand.
- By 2017, a gas-fired unit with a heat rate of 11,000 Btu/kWh will be the peaking marginal unit most of the time.
- By 2017, a gas-fired unit with a heat rate of 6,600 Btu/kWh will be the marginal unit most of the time during off-peak hours.
- Existing KGE units will continue to generate at their 2012 levels (maintain the same capacity factor).
- KGE will continue to buy/sell energy from/to other market regions.

- Both transmission improvements and the fact that new gas-fired units will be setting the marginal price in all areas will cause the market price differences among the regions to diminish – each market area will have the same marginal price most of the time.
- The extended analysis used the same fuel price assumptions that were used for the base case and the fuel sensitivities.

The main assumptions for the existing KGE units are summarized below in Table 6-5. All of the resource information is based on the data provided in the Henwood database.

Table 6-5
KGE GENERATING STATIONS 2001 OUTPUT VARIABLES

TransArea	Station	Unit Type	Year	Total Cost	Generation (GWh)	Fuel Cost ($000's)	Start Cost ($000's)	VOM Cost ($000's)	Fixed O&M (000's)*
SPP	Gordon Evans E 1	Gas	2001	$3,873	126	$3,673	$12	$187	$674
SPP	Gordon Evans E 2	Gas	2001	$12,959	430	$12,196	$123	$641	$1,650
SPP	Gordon Evans E 3	New CT	2001	$5,231	163	$4,715	$15	$501	$674
SPP	Jeffrey EC 1	Coal	2001	$71,840	5,265	$66,996	$110	$4,734	$7,350
SPP	Jeffrey EC 2	Coal	2001	$71,227	5,410	$66,256	$106	$4,865	$7,729
SPP	Jeffrey EC 3	Coal	2001	$73,032	5,264	$68,205	$95	$4,733	$7,402
SPP	Lacygne 1	Coal	2001	$45,885	5,121	$37,052	$89	$8,744	$11,521
SPP	Lacygne 2	Coal	2001	$44,616	5,016	$35,967	$84	$8,565	$11,183
SPP	Murray Gill EC 1	Gas	2001	$119	3	$101	$11	$7	$371
SPP	Murray Gill EC 2	Gas	2001	$484	13	$419	$36	$29	$596
SPP	Murray Gill EC 3	Gas	2001	$2,029	63	$1,878	$7	$144	$862
SPP	Murray Gill EC 4	Gas	2001	$1,859	56	$1,727	$6	$126	$854
SPP	Neosho 3	Gas	2001	$546	16	$489	$42	$15	$687
SPP	Wichita EC 5	Oil	2001	$0	-	$0	$0	$0	$17
SPP	Wolf Creek 1	Nuclear	2001	$56,803	7,876	$45,237	$0	$11,566	$88,331

*From Henwood.

ENERGY MARKET RESULTS

The average cost for a new combustion turbine is based on a heat rate of 11,000 Btu/kWh, and a combined cycle unit based on a heat rate of 6,800 Btu/kWh in 2001 declining to 6,600 Btu/kWh by 2008 to reflect potential technology improvements.

Capacity prices are assumed to ramp up, by 2001, to full fixed cost based on a simple cycle combustion turbine. The other assumptions used to develop the price include: 20-year finance period, debt to equity ratio of 80/20, 8 percent cost of debt, and 13.5 percent cost of equity. Capacity prices for 2002 to 2022 are shown in Table 6-6.

Table 6-6
SPP MARKET PRICE FOR POWER ($/MWh)

Year	Energy	Capacity	All-In Energy
2002	$27.71	$7.72	$35.43
2003	$28.23	$8.53	$36.76
2004	$29.13	$9.44	$38.58
2005	$30.47	$10.32	$40.79
2006	$32.18	$9.95	$42.14
2007	$33.20	$11.50	$44.70
2008	$35.08	$11.04	$46.11
2009	$36.19	$11.37	$47.56
2010	$37.16	$11.86	$49.02
2011	$38.57	$11.80	$50.36
2012	$39.15	$12.94	$52.09
2013	$40.13	$13.26	$53.39
2014	$41.05	$13.57	$54.62
2015	$41.91	$13.85	$55.76
2016	$42.70	$14.11	$56.81
2017	$43.41	$14.35	$57.76
2018	$44.05	$14.56	$58.61
2019	$44.61	$14.75	$59.36
2020	$45.18	$14.93	$60.11
2021	$45.75	$15.12	$60.88
2022	$46.33	$15.31	$61.65

PROJECTED FINANCIAL OPERATIONS

To determine the potential economic impact on ratepayers of the operation of a municipal electric utility, Beck has developed a financial forecast of retail electric rates for Wichita citizens (in $ per MWh). This forecast provides a forecast of average retail rates for all retail customers to be served by the municipal electric utility. Beck has developed a similar forecast of retail rates for Wichita citizens assuming service from the existing KGE system. In both cases, average retail rates were applied to the forecasted customer load to determine future annual revenue streams. The difference in forecasted revenue streams between the municipal scenario (electrical service by the City, referenced as the "municipalization case" or the "Wichita Municipal Utility [WMU] case") and the status quo scenario (continued service by KGE, the "status quo case" or the "KGE case") is defined for this study as the economic impact on ratepayers of the municipalization effort.

This section describes in detail the principal considerations and assumptions in developing the forecasts, forecast results and the influence of key variables and assumptions on projected outcomes.

The financial analysis as presented herein is a cost based analysis. The analysis assumes that retail rates will be set to meet the utility's revenue requirements. For the KGE system, the revenue requirement has been developed using a "utility-basis" methodology. This methodology is consistent with the ratemaking principals used for investor owned utilities. For the municipal system, the revenue requirement has been developed using the "cash-basis" methodology. This methodology is consistent with rate-making principals used for municipal electric utilities, which recognizes that the primary concern of a municipal electric utility is to meet debt service coverage requirements.

FORCASTING VARIABLES

When forecasting performance, changes in certain key variables may materially influence the end result. In this specific analysis, assumptions surrounding the market price of power, customer load growth, and other variables have a significant impact on projected retail rates in both the "status quo" and the "municipalization" cases.

Using probability theory and techniques, Beck has evaluated the impact of individual variables on study results to identify which variable and/or study assumptions are the most influential on results. Once these key variables and assumptions were identified, probability distributions were developed that bracket realistic variations for each assumption. Using these techniques a distribution of outcomes was calculated and compared to the economic impact on the average ratepayer over multiple scenarios. This approach provides the City with valuable insight concerning the potential financial risk associated with its municipalization effort, as well as an initial determination of the confidence of benefits achievable from municipalization. The results of this are discussed in Section 8 of this report.

KGE Status Quo Case

In order to determine the economic impact of the municipalization effort, Beck developed a projection of the retail rates for the existing KGE system. This process included the development of a forecast of KGE's cost of service, in which a total system revenue requirement was calculated for the period 2001 – 2021. For each year of the study period, KGE's cost of service was allocated across its wholesale and retail markets. The retail markets were approximated by the four main categories of retail customers; residential, commercial, industrial and street-lighting (public authority).

The KGE revenue requirement includes O&M expense, depreciation expense, interest expense, taxes, other income sources, the cost of capital and operating margins. These specific items are listed in Table 7-1 below.

Table 7-1
COMPONENTS OF KGE'S REVENUE REQUIREMENT

- Operation & Maintenance Expense
  - Production
    - Fuel
    - Purchased Power
    - Other Fixed
  - Transmission
  - Distribution
  - Administration & General
- Depreciation
- Interest Expense
- Taxes
  - Payroll
  - Property
  - Income
- Other Income & Deductions
- Return on Equity

The total KGE revenue requirement was determined from the sum of the expenses and income requirements listed above. The cost of service associated with off-system sales, (fuel, O&M, demand charges [fixed costs recovery] and wholesale margin) was also deducted from the total revenue requirement to calculate the retail revenue requirement. O&M expenses include those required to operate and maintain each primary function of the utility (i.e. production, transmission, distribution and general).

O&M expenses associated with the production function consist of fixed and variable costs. Fixed production costs consist primarily of labor and maintenance expenses and were projected based on KGE's historical levels adjusted for inflation. Variable production costs, which consist primarily of fuel, purchased power and variable O&M expense, were obtained from the market-pricing model discussed in Section 6. Transmission, distribution and general operation and maintenance expenses were obtained from an analysis of KGE's historical costs. The projection of the expenses included in the revenue requirement is discussed in detail later in this section.

LOAD GROWTH

Meeting system load requirements is one of the primary drivers influencing a utility's overall capital requirements and related cost of service. Load growth for the KGE system was based on the increases in system load as projected by KGE in their EIA Form 411 10-year projections for 1998 (Table 7-2). Beyond 2008, KGE system load was assumed to grow at 2.6 percent per year, based on an average of the last three years of the load growth forecast (2006-2008).

Table 7-2
PEAK LOAD GROWTH FORECAST

Year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008*	2009
Peak Load (MW)	2,205	2,114	2,160	2,208	2,258	2,306	2,355	2,404	2,467	2,532	2,595	2,662
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Peak Load (MW)	2,731	2,801	2,873	2,948	3,024	3,102	3,182	3,264	3,348	3,435	3,523	3,614

* Last year of KGE's forecast from EIA Form 411.

RETAIL CUSTOMERS

The projection of the number of customers for the KGE system was determined for each retail customer class, and was based on a combination of historical customer growth and related kWh usage per customer assumptions.

Customer growth was evaluated historically by developing a kWh per customer ratio for each rate class. These ratios were escalated based on historical trending. In other words, these ratios have changed over time, and this change is projected over the study period. The usage per customer ratios are linked directly to system load projections. Therefore, as projected load fluctuates, as described in the prior section, the number of customers fluctuates as well. Additionally, as the number of customers fluctuates, so does the required investment and related expense on the distribution system. Table 7-3 provides a summary of the number of KGE customers for 1999.

Table 7-3
NUMBER OF KGE CUSTOMERS

	% of Total	KWh	Usage per Customer	Annual Average Increase Per Class	Number of Customers
Customer Class			MWh/Customer		1999
Residential	30.5%	2,566,926	10.0	1.07%	257,426
Commercial	26.1%	2,194,091	85.4	0.07%	25,688
Industrial	42.9%	3,608,174	1,016.9	4.03%	3,548
Public Street & Highway Lighting	0.6%	50,021	N/A	N/A	N/A
Total Retail Sales		8,419,212			

PRODUCTION

KGE owns and operates various production resources within the SPP. KGE's ownership interest of specific generation stations in the SPP are summarized in Table 7-4, below.

Table 7-4
KGE'S OWNERSHIP INTEREST OF SPP PRODUCTION RESOURCES

Plant Name	Percent Ownership	Fuel Type
Jeffrey Energy Center	20%	Coal
Wolf Creek	47%	Uranium
Lacygne #1	50%	Coal
Lacygne #2	50%	Coal
Neosho	100%	Gas
Gordon Evans	100%	Gas
Murray Gill	100%	Gas
Wichita	100%	Oil

KGE does not own 100 percent of most of its production assets. Therefore, fixed and variable expenses for these units have been adjusted in the KGE revenue requirement to account for KGE's ownership share.

To meet future load growth, capacity additions were added to maintain a 12 percent reserve margin imposed by SPP. Over the study period, it was assumed that KGE would not build additional production facilities to meet its reserve requirements. When retail load growth reduced KGE's reserve margin below 12 percent, it was assumed that KGE would purchase capacity and energy on the market to meet its retail load requirements (wholesale sales and exchanges were assumed to go to zero). When KGE's reserve margin was greater than 12 percent, it was assumed that KGE's excess capacity was sold into the market at market rates. Market capacity and energy rates are established in Section 6.

System energy requirements were projected assuming a system load factor of 47.8 percent over the study period, based on historical analysis.

Variable production O&M expense was obtained from the market-pricing model described in Section 6. The market price model dispatches each of the KGE generation resources into the market. The dispatch depends on the type and price of fuel utilized (i.e. gas, oil, coal or nuclear) and the type of technology employed (i.e. combustion turbine, steam turbine, etc).

TRANSMISSION

Transmission investment and O&M expense were projected based on historical KGE data. Investment and expense levels were escalated by a real growth factor as well as projected inflation. The real growth factor was calculated by comparing yearly changes in values to the relative change in the Gross Domestic Product ("GDP") as recorded by the U.S. Department of Commerce. The change in GDP was therefore used to "deflate" the change in expenses reported and account for the impacts of inflation on these expenses over time. The results indicated that transmission investment has remained relatively stable over the 9 years of historical data reviewed. To meet system load growth, transmission investment requirements were projected on a dollars per kW basis beginning at $102 per kW (1999 calculated value). Transmission expense was projected as a percent (6.55 percent) of gross transmission plant investment

DISTRIBUTION

Distribution investment and O&M expense were projected based on historical data from KGE. Similar to the methodology described above, investment and expense levels were escalated by a real growth factor as well as projected inflation. The results indicated that distribution investment has had real growth of approximately 2.6 percent annually over the 9 years of historical data reviewed. To meet system load growth, distribution investment requirements were projected on a dollars per customer basis beginning at $1,767 per customer. Distribution expenses were projected as a percent (3.88 percent) of Gross Distribution Plant Investment.

GENERAL

General plant and O&M refers to facilities common to all facets of the utility and include items such as vehicles, office buildings, storage facilities, etc. General plant investment and O&M values were obtained from an analysis of the historical relationship between general plant values and total gross utility plant. General plant was projected at 2.49 percent of total KGE gross plant-in-service. General expenses were projected as a percent of gross plant (93.3 percent). This value was determined from a review of historical data.

DEPRECIATION

Using available historical data, depreciation factors were determined for the utility functions (production, transmission, distribution, and general plant) and are provided in Table 7-5 below. These factors were determined by dividing the annual depreciation expense of each function into the average balance of gross plant-in-service. The average balance of gross plant-in-service was determined by averaging the beginning-of-year and end-of-year balances over a twelve-month period.

The annual depreciation factors are applied on a "straight-line" basis. The inverse of annual depreciation factors yields the estimated useful life of each asset. Production plant assets have different depreciation factors depending on the type of technology. The estimated useful economic life of KGE assets is presented below.

Table 7-5
KGE DEPRECIATION FACTORS

Plant-in-Service	Depreciation Factor	Economic Life (Years)
Steam Production Plant	2.8%	36
Nuclear Production Plant	2.6%	38
Other Production Plant	2.5%	40
Transmission Plant	2.9%	35
Distribution Plant	2.4%	41
General Plant	2.9%	34

Depreciation factors are applied annually to KGE gross plant values. Gross plant values include existing plant, capital additions to maintain existing plant, and capital additions for growth. Existing plant values were obtained from FERC Form 1 data.

To maintain existing plant, net additions were determined from historical values and projected as an escalation factor to gross plant-in-service. The net additions factor takes into consideration replacement facilities as well as equipment that has been retired with remaining "economic" life. New plant additions were projected as described above. Table 7-6 below provides the plant-in-service values for KGE in 1999.

Table 7-6
1999 KGE PLANT-IN-SERVICE VALUES

Plant-in-Service	Production Plant			Transmission Plant	Distribution Plant	General Plant
	Fossil-Steam	Nuclear	Other			
Gross Plant-in-Service[1]	$574,153,867	$1,378,237,869	$342,449	$259,127,696	$516,870,444	$71,985,508
Accumulated Depreciation[1]	$328,391,204	$460,885,272	$4,315	$105,308,127	$188,367,819	$29,799,153
Net Plant-in-Service[1]	$245,762,663	$917,352,597	$338,134	$153,819,569	$328,502,625	$42,186,355
Average Balance Gross Plant-in-Services	$555,988,075	$1,377,792,803	$171,225	$259,988,273	$506,636,261	$72,751,801
Yearly Net Additions (Renewals & Replacements)	$32,331,584	$890,132	$342,449	($1,721,154)	$20,468,367	($1,532,586)

1. End of Year ("EOY") values.

INTEREST EXPENSE

Interest expense KGE's cost of debt on an annual basis. For this analysis, Beck assumed a long-term debt to equity ratio of 42:58 for KGE (based on historical data). Therefore, 42 percent of KGE's net plant-in-service is assumed to be debt financed. Reviewing KGE's historical cost of debt and taking into consideration future changes in the debt market, Beck assumed KGE's future cost of debt will be 2 percent above inflation.

TAXES

Taxes are an important element of an investor owned utility's revenue requirement. KGE pays primarily three types of taxes; payroll, property (or ad valorem) and income. In addition, KGE collects a 5 percent franchise fee payable to the City of Wichita In this analysis, the franchise fee is not included in the utilities revenue requirement as it is a pass through, i.e. collected from customers and remitted to the City.

Payroll taxes were projected based on the historical relationship between payroll expense and total O&M excluding fuel and purchased power. This ratio historically averaged approximately 19.8 percent.

Property taxes were projected as a percentage of the end of year gross plant-in-service value. Historically, this value averaged approximately 1.44 percent.

Net income taxes were projected by calculating a net margin from operating revenue less total O&M, deprecation, and interest expense. Values for net income taxes paid were compared to the calculated net margin over the historical study period. This ratio averaged approximately 25.2 percent.

NET OTHER INCOME AND DEDUCTIONS

Net other income and deductions includes such items as other income, miscellaneous income deductions, taxes on other income, and net interest charges. This item is a relatively small component of the utility's revenue requirement. Projections were based on an annual average of historically calculated values (approximately $8.4 million) and escalated at inflation.

AFTER TAX MARGIN

KGE's profitability on overall operations is represented in this analysis as an after tax margin. The margin includes KGE's cost of equity and additional retained earnings to the company. This margin is expressed as a ratio of margin to net plant-in-service, or a measure of return on assets. This factor is calculated based on the historical relationship between after tax margin and net plant-in-service. The after tax margin to net plant-in-service ratio for KGE was calculated to be approximately 7.03 percent. A comparison of KGE to other utilities suggests that the KGE value calculated is similar to the average for SPP.

The after tax margin was calculated based on revenues generated from current rate levels plus other income sources, less O&M expenses, depreciation, interest expense and taxes. Net plant-in-service was calculated based on gross plant-in-service, less depreciation.

RETAIL RATES

Average retail rates were determined based the components of the revenue requirement as described above. This revenue requirement was divided by the total retail sales (in MWh's) to determine an average retail rate. This retail rate was allocated to each customer class based on historical relationship values. As noted above, a 5 percent franchise fee was applied to KGE rates reflecting the full cost to Wichita ratepayers.

KGE PROJECTION – KEY VARIABLES

As described above, the projection of KGE's revenue requirement and related retail rates considers many variables with varying impact on study results. To understand the impact of these variables on the study outcome, each variable has been analyzed as it impacts the NPV. The NPV is calculated for the projected revenue stream from retail rates over the study period for each case. The difference between the NPV's of projected rate revenue for each case is an economic indicator of the impact of municpalization on Wichita ratepayers.

In analyzing the relative importance of study variables, the *Crystal Ball*™ analytical package was used. The results of this evaluation for the KGE include the impact of selected study assumptions having the most impact on the NPV value.

Certain of the variables are correlated in the model. Correlated variables are statistically linked, which recognizes that the change in one variable will impact the change in another variable either a positively (same direction) or negatively (opposite direction). For example, inflation and interest rates have a positive correlation. As inflation rises, interest rates rise as well. A correlation factor is used to recognize this relationship and has been included in the model.

The assumptions with the greatest influence on KGE's NPV value and therefore its retail rates are:

- After Tax Margin
- Inflation
- Usage per Customer
- Fuel Cost

After Tax Margin – The after tax margin is a key assumption in the study, as in KGE's case, where small changes in this value can cause large changes in the KGE revenue requirement. A historical review of after-tax margin (as a percent of net plant-in-service) indicated an average of 7.03 percent with significant variability in this number from year to year. To consider reasonable variations in the after tax margin variable, and to evaluate its impact on study results, it has been assumed that the distribution of the after tax margin variable is a normal mean value of 7.03 percent and a standard deviation of 0.70 percent. A normal distribution was assumed because there is an equal chance that the expected value for this variable will either be above or below the mean value.

Inflation – Inflation is a key assumption in the KGE projection because the utility is capital intensive with a significant amount of generation investment. Inflation assumptions heavily influence the cost of on-going improvements, new capital projects, the cost of capital itself, and labor and expense required to maintain and operate the system. To consider reasonable variations in the inflation variable and to evaluate its impact on study results, it is assumed that the distribution of the inflation variable is lognormal, with a mean of 2.6 percent for years 2001-2003, and 2.5 percent for the rest of the study period. This number was obtained from the CPI Blue-Chip Economic Indicators, as published by the U.S. Department of Commerce. The standard deviation is assumed to be 0.32 percent based on an analysis of historical data subjected. A lognormal distribution was selected to reflect that inflation generally moves upward, and that periods of deflation are quite rare.

Fuel Cost – The price of fuel is also an important variable relative to the KGE's retail rates. KGE's production is mostly driven by its coal and nuclear resources. To understand the significance of fuel price on the KGE system, it is important to look beyond the direct effect of this variable on the analysis and consider variable correlation. In this model, fuel oil, natural gas, coal, inflation and system demand have been correlated. These correlation coefficients are provided in Table 7-7.

Table 7-7 CORRELATION MATRIX					
	Coal	**Gas**	**Oil**	**Inflation**	**Demand**
Coal	1	-0.023549	-0.082381	-0.20657	0
Gas	-0.023549	1	0.27009	0.036895	0
Oil	-0.082381	0.27009	1	0.11454	0
Inflation	-0.20657	0.036895	0.11454	1	0
Demand	0	0	0	0	1

The above correlation matrix indicates that natural gas is most highly correlated with fuel oil. Therefore, changes in the price of fuel oil will impact gas prices in the model. This relationship will have as a significant indirect impact on the model as it influences KGE's cost of fuel for the majority of it resources.

To consider reasonable variations in the price of fuel and to evaluate the impact of these variables on the study results, a fuel price factor was utilized. Individual price factors were developed for each fuel price projection, however each factor was assumed to have a lognormal distribution with a mean value of 1.0. Summary statistics for these fuel price variables are presented in Table 7-8 below.

Table 7-8 SUMMARY STATISTICS FOR FUEL PRICE FACTORS		
Fuel	**Mean**	**Standard Deviation***
Coal	1.0	0.029
Natural Gas	1.0	0.261
Oil	1.0	0.258

*Standard deviation factors varied slightly in early years of the study (+/- 0.02%).

A log normal distribution was selected to reflect that fuel prices generally move upward. The standard deviation was based on a historical review of changes in fuel prices over time.

Usage per Customer – For the commercial and industrial class, and to a lesser extent the residential class, electricity usage per customer (MWh/customer) assumptions in the model are important as they directly influence the amount of new investment required to meet load growth. It is likely that variations in usage per customer ratios are heavily influenced by variation in weather. To consider reasonable variations in the usage per customer variables and to evaluate the impact of these variables on study results, a normal distribution was assumed for these variables (Table 7-9).

Table 7-9 USAGE PER CUSTOMER (MWh)		
Class	**Mean**	**Standard Deviation**
Residential	10.0	1.0
Commercial	85.4	8.5
Industrial	1,016.9	101.7

A normal distribution was applied because there is an equal chance that the expected value will either be above or below the mean value. A shown in the above table, a standard deviation of +/- 10 percent was used for each variable based on the historical review of KGE class usage per customer ratios.

WICHITA MUNICIPALIZATION CASE

In order to determine the economic impact of the municipalization effort, Beck developed a projection of the retail rates for a municipal utility serving the citizens of Wichita. The Wichita municipalization case (or WMU case) assumes that the City will purchase, own and operated a municipal electric utility with assets as described in previous sections of this report. For the purposes of this study, it is assumed that such a utility will commence operation on January 1, 2002.

The utility revenue requirement as described herein is a cost based analysis for the twenty-year period study. The analysis assumes that retail rates will be set to meet the municipal utility revenue requirement. For the municipal system, the revenue requirement has been developed using the "cash-basis" methodology. This method recognizes that the primary concern of a municipal electric utility is to meet debt service coverage requirements. For the WMU case, the primary components of the utility revenue requirement are provided in Table 7-10 below.

TABLE 7-10
COMPONENTS OF WICHITA MUNICIPAL SYSTEM
REVENUE REQUIREMENT

- Operation & Maintenance Expense
  - Production
    - Purchased Power
  - Transmission Wheeling
  - Distribution
  - Administration & General
- Debt Service
- Debt Service Coverage
- Capital Paid From Current Earnings
- Funding of Required Reserves
- Contributions to the City

The total WMU revenue requirement was determined from the sum of the expenses and income requirements listed above. O&M expenses included those required to operate and maintain each primary function of the utility (i.e. production, transmission, distribution and general).

O&M expenses associated with the production function consist solely of purchased power costs to meet customer load. Purchased power costs were obtained from the market-pricing model as described in Section 6. Transmission expense is exclusively related to wheeling expense related to power purchases. Distribution and general plant-in-service assumptions are consistent with those used in the KGE analysis.

Additional utility expenses included debt service, reserve requirements, capital to be paid from current earnings and payments to the City. To the extent retail rates fund all of the above items, but do not meet the utilities required minimum debt service coverage requirements, additional funds to meet debt service coverage are also required.

LOAD GROWTH

The load-forecast assumptions for the WMU case are identical to the KGE case. Because the market price forecast includes an “all-in" price (demand and energy), the WMU case only forecasts system energy requirements. Using actual 1999 kWh sales data for Wichita customers and assuming a constant system load factor, system energy requirements are projected based on KGE demand requirements. In other words, if KGE system demand was projected to increase by 2 percent, then WMU demand and corresponding energy requirements were projected to increase by 2 percent as well. Table 7-11 provides the WMU system energy requirements.

Table 7-11
WMU NET ENERGY FOR LOAD FORECAST (GWh)

Year	2002	2003	2004	2005	2006	2007	2008*	2009	2010	2011
Net Energy For Load	6,354	6,489	6,627	6,765	6,942	7,125	7,302	7,491	7,684	7,882
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Net Energy For Load	8,086	8,295	8,509	8,728	8,954	9,185	9,422	9,665	9,915	10,170

RETAIL CUSTOMERS

The projection of the number of customers for the WMU system was determined for each retail customer class, and was based on a combination of historical customer growth and similar kWh usage per customer assumptions that were developed for the KGE case.

Customer growth was evaluated historically by developing kWh per customer ratios for each rate class. These ratios were escalated into the future based on historical trending. The usage per customer ratios are linked directly to system load projections. Therefore, as projected load fluctuates the number of customers fluctuates as well. Additionally, as the number of customers fluctuates, so does the required investment and related expense on the WMU distribution system.

Table 7-12 provides a summary of number of customers for 1999 for the WMU system.

Table 7-12
WMU SYSTEM – 1999 NUMBER OF CUSTOMERS

	% of Total	KWh	Usage per Customer	Annual Average Increase Per Class	Number of Customers
Customer Class			MWh/Customer		1999
Residential	27.3%	1,544,921	10.0	1.07%	156,108
Commercial	30.2%	1,708,925	85.4	0.07%	16,029
Industrial	42.0%	2,371,316	1,016.9	4.03%	949
Public Street & Highway Lighting	0.5%	28,504	N/A	N/A	N/A
Total RetailSales		5,653,666			

PRODUCTION

WMU is assumed to have no production plant investment and will purchase all system power requirements from the SPP at projected market prices. Because WMU is not a generating utility, it is not required to purchase system reserves.

TRANSMISSION

WMU is assumed to have no transmission plant investment. (Limited transmission facilities described in Section 3 are assumed to be in the distribution plant investment.) Transmission expense is associated with wheeling power purchases to the system. Wheeling charges were determined from existing rates observed in the wholesale market, which averaged approximately $2.29/MWh in 2000. These costs are escalated at inflation.

DISTRIBUTION

WMU will have significant distribution system investment and expenses. Investment values were determined as described in Section 3 of this report. Distribution expenses were projected as a percent of distribution plant investment, consistent with factors developed for the KGE system. To incorporate inefficiencies in operations during the first few years of municipalization, distribution O&M expenses have been increased by 15 percent, 10 percent, and 5 percent respectively for each of the first three years of the WMU operations.

GENERAL

General plant-in-service supporting the distribution system investment is estimated to be 2.6 percent of the distribution plant-in-service. This percentage is consistent with general plant investment as a percent of total assets within the KGE system.

General plant O&M has been set equal to distribution O&M expense based on a benchmarking review of other municipal utilities. This review indicates that administration and general expense range from 80 to 100 percent of distribution operation and maintenance expense for municipal utilities without production investment.

DEBT SERVICE

It is assumed that the City will finance 100 percent of the cost of acquiring and funding a municipal electric system. The acquisition price includes the costs of facilities, severance, and stranded investment. In addition to the costs paid to KGE, WMU will be expected to set up required reserve funds, operating funds, and pay the cost associated with the issuance of bonds.

Debt service payments are the annual obligations payable by WMU to finance the acquisition. It was assumed that the City will acquire KGE distribution property at a price of $323.7 million (See Section 3). The City will also incur additional costs associated with the acquisition of KGE distribution properties related to severance and stranded cost issues. As presented in Section 2 of this report, estimated severance costs are approximately $36.6 million. As presented in Section 5 of this report, an estimate of approximately $145.3 million has been assumed for potential stranded investment costs.

Given the above components, the City will be expected to borrow approximately $66.5 million to be paid on a leveled basis over 30 years at a coupon rate of 8.5 percent. This coupon rate reflects the current cost of taxable municipal bonds. The specific elements comprising the $665.6 million of debt is presented in Table 7-13:

Table 7-13
INITIAL MUNICIPAL UTILITY FINANCING

Item	Amount
Facility Cost*	$336.7 million
Stranded Investment	$145.3 million
Severance Cost	$36.6 million
Funding of Utility Reserves & Operating Funds	$123.7 million
Bond Issuance Fees	$23.3 million
Total Bond Principal	$665.6 million

*Includes distribution assets, general plant and acquisition related costs.

It was assumed that the debt would require a minimum debt coverage ratio of 1.2, which is reasonable for a municipal entity. It was assumed that the City would earn a return on idle investment of inflation plus 2 percent. Inflation, as described in Section 6, was assumed to be 2.5 to 2.6 percent over the study period.

CAPITAL ADDITIONS

The municipal utility will be required to fund future capital additions to the distribution system from its current earnings. Funds set aside for this purpose reside in the depreciation reserves fund as decried below.

FUNDING RESERVES AND CAPITAL ADDITIONS

On an on-going basis, the municipal utility will maintain the following reserve balances from current earnings:

Operations and Maintenance Reserve – This reserve is funded at two months of total system operations and maintenance expense including purchased power. The use of this fund is to pay normal on-going expenses.

Principal and Interest Fund – This reserve is funded equal to one years debt service. The use of this fund is to guarantee debt service payments.

Contribution Reserve – This reserve is funded at two months of the utilities expected payment to the City. The use of this fund is to pay the City's contribution on an on-going basis.

Depreciation Reserves – This reserve is funded at 15 percent of the utilities total revenue requirement less purchased power and wheeling expense. The purpose of this fund is to pay for renewal and replacements on the system.

Improvement Reserves – This reserve is funded at 0.5 percent of the utilities net plant-in-service. The purpose of this fund is to pay for capital additions on the system.

TAXES

Taxes for WMU will consist of payroll tax and a payment to the City. Payroll taxes were projected in a manner consistent with the KGE case. These projections were based on the historical relationship between payroll expense and total O&M excluding fuel and purchased power. This ratio historically averaged approximately 19.8 percent. A payment to the City was calculated based on 5 percent of the WMU's gross receipts (revenue requirements).

OTHER INCOME

For WMU, the primary source of other income will be from interest earnings on reserve balances. As noted above, it was assumed that WMU will earn inflation plus 2 percent on these monies.

WMU PROJECTION – KEY VARIABLES

As described above, the projection of WMU's revenue requirements and related retail rates considers many variables with varying impact on study results. To understand the impact of these variables on the study results, the input of each variable, as it pertains to the NPV, was determined. As with the KGE system, an NPV value for the projected revenue stream from retail rates over the study period was calculated. As noted in the KGE case, the analysis projects WMU rates over a twenty-year period, however key variables were determined for the first twelve years of the analysis to be consistent with the production cost model assumptions.

The most important variables influencing WMU's retail rates are:

- Gas prices
- Inflation
- Fuel Oil Cost
- System Demand

Gas Prices – The price of natural gas is a key assumption in the WMU study, as gas prices heavily influence price of purchased power which is WMU's single largest cost component. SPP generation resources on the margin are generally gas-fired units. Therefore, gas price heavily influences market price even though other types of fuel resources supply market load requirements. As with the KGE case, a lognormal distributed natural gas price factor was assumed. This lognormal distribution of the gas price factor assumed a mean value of 1.0 and a standard deviation of 0.26.

The standard deviation was based on a historical review of changes in gas prices over time.

Inflation – Similar to the KGE projection, inflation is a key assumption in the WMU case. Inflation assumptions heavily influence the cost of on-going improvements, new capital projects, the cost of capital itself, and labor and expense required to maintain and operate the system. The treatment of inflation for the WMU case is identical to that described in the KGE case description.

Fuel Oil – Fuel oil has a significant impact on the WMU revenue requirement because, it is correlated with natural gas, coal, inflation and demand. The result of these correlations are such that changes in the price of oil influence the price of natural gas, which influences the market price of power. Therefore fuel oil has a significant indirect impact on the model as it influences WMU's cost of purchased power.

Demand – Compared to KGE's system, WMU's revenue requirement is more demand sensitive because the utility must respond to fluctuations in system load through variations in purchased power and distribution system additions. The KGE system, as a result of its excess capacity can absorb load growth in the earlier years of the analysis. Therefore, fluctuation in growth have less of an impact on system costs as a significant portion of KGE's costs are fixed and related to generation assets.

In WMU's case, fluctuations in load must be met by the market and with new capital projects. The impact of these fluctuations on the revenue requirement is much greater than for KGE. These fluctuations impact retail rates as the fixed components of the utilities costs (i.e. debt service) are spread over fluctuating energy sales. This fluctuation causes variations in retail rates. To consider reasonable variations in the demand variables and to evaluate these variables impact on the study results, Beck has assumed a lognormal distribution for a demand factor with a mean value of 1.0 and a varying standard deviation value, as provided in Table 7-14.

Table 7-14
DEMAND INDEX

Year	Mean	Standard Deviation
2001	1.0	0.00
2002	1.0	0.06
2003	1.0	0.09
2004	1.0	0.10
2005	1.0	0.12
2006	1.0	0.13
2007	1.0	0.15
2008	1.0	0.17
2009	1.0	0.18
2010	1.0	0.19
2011	1.0	0.21
2012	1.0	0.22

As shown in the above table, the standard deviation values increase over time which reflects the greater degree of uncertainty related to load growth as the forecast moves into the future.

ANALYSIS RESULTS

For each variable as described in Section 7, multiple scenarios for the KGE Case and the WMU case were developed to evaluate potential impacts on Wichita ratepayers. As described in earlier sections, *Crystal Ball*™ analytical package was used to evaluate study results. *Crystal Ball*™ allows for a stochastic (random), evaluation of key model assumptions given specific distribution profiles with specified mean and standard deviations.

To evaluate the impact on Wichita ratepayers over the twenty-year study period, the NPV, in year 2000 dollars, of the revenue streams for the KGE case and the WMU case were calculated. The difference in these NPV's is the same as the differences between the cost to ratepayers of receiving comparable service from KGE under "status quo" assumptions and Wichita under a municipalization scenario. The retail rate resulted in the following approximate mean values for NPV, as provided in Table 8-1.

Table 8-1
AVERAGE RETAIL RATE COMPARISON

Item	Amount (NPV, Year 2000)
KGE (Status Quo Case)	$5,136,700,000
WMU (Municipalization Case)	$4,482,300,000
Potential Savings Under Municipalization Case (Difference)	$654,400,000

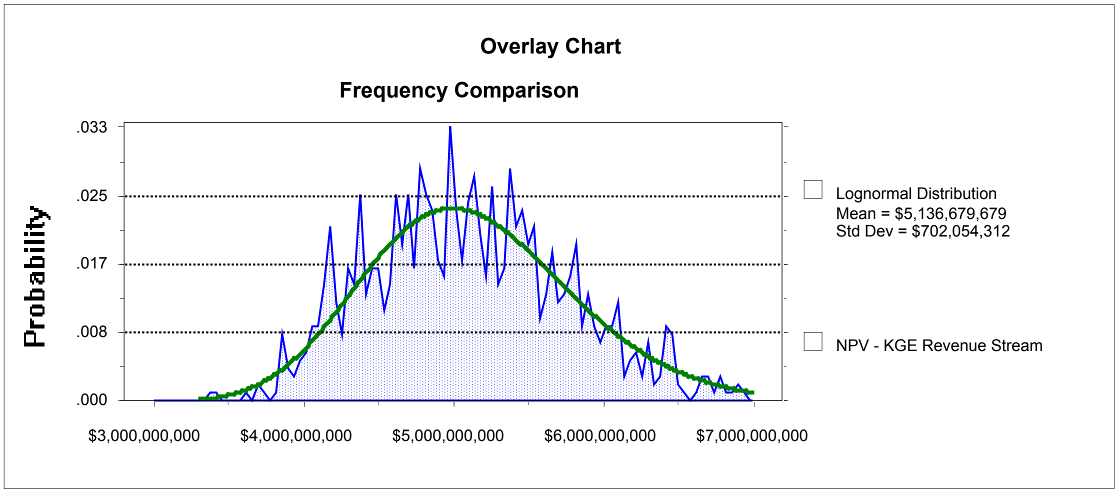
As shown above, Wichita citizens may benefit from municipalization through lower rates totaling approximately $654 million.

KGE RESULTS

A closer examination of the KGE study results indicates that the case mean, or most likely NPV value, is approximately $5.1 billion, which can vary between approximately $4.4 billion and $5.8 billion within one standard deviation.

In other words, given the variations in study assumptions analyzed, NPV is expected to be between $4.4 billion and $5.8 billion for 66 percent of the time. The NPV is expected to be between approximately $3.5 billion and $7.0 billion given consideration to all possible outcomes (i.e., 100 percent of the time). This is shown in Figure 8-1 below.

Figure 8-1
KGE – NPV OF RETAIL RATE REVENUE



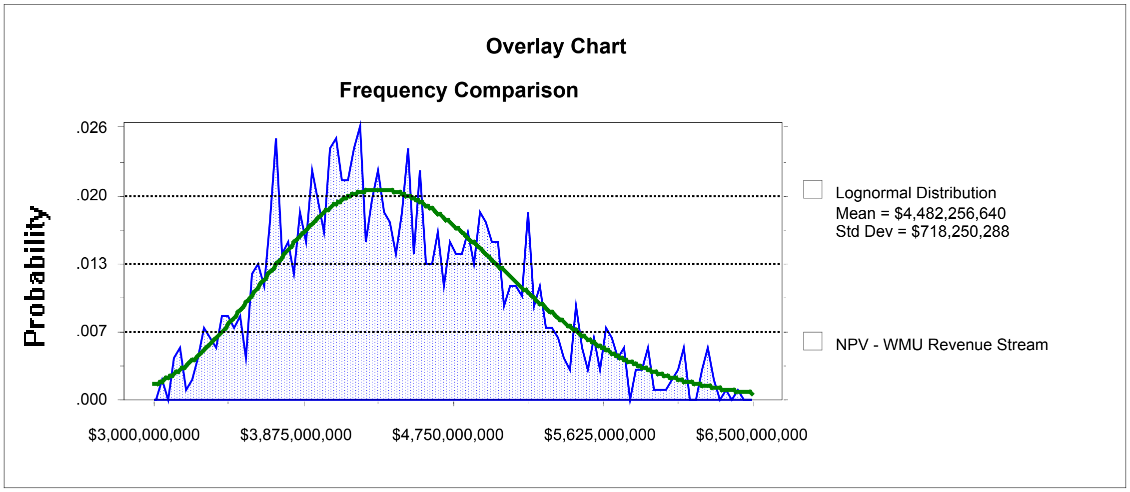
Extreme values are generated when the variables of after tax margin, inflation, fuel cost, and usage per customer are all relatively high or low for most or all of the years of the study period. These instances are very rare, as indicated above (less than 0.8 percent of the time).

WMU RESULTS

A closer examination of the WMU study results indicates a similar shaped distribution of NPV values, however with a lower mean value. For the WMU case, the most likely NPV value is approximately $4.5 billion, which can vary between $3.8 billion and $5.2 billion within one standard deviation.

Given the variations in study assumptions analyzed, the expected NPV is between $3.8 billion and $5.2 billion for 66 percent of the time. The NPV is between $3.0 billion and $6.5 billion given consideration to all possible outcomes (i.e. 100 percent of the time). This distribution is provided in Figure 8-2 below.

Figure 8-2
WMU – NPV OF RETAIL RATE REVENUE

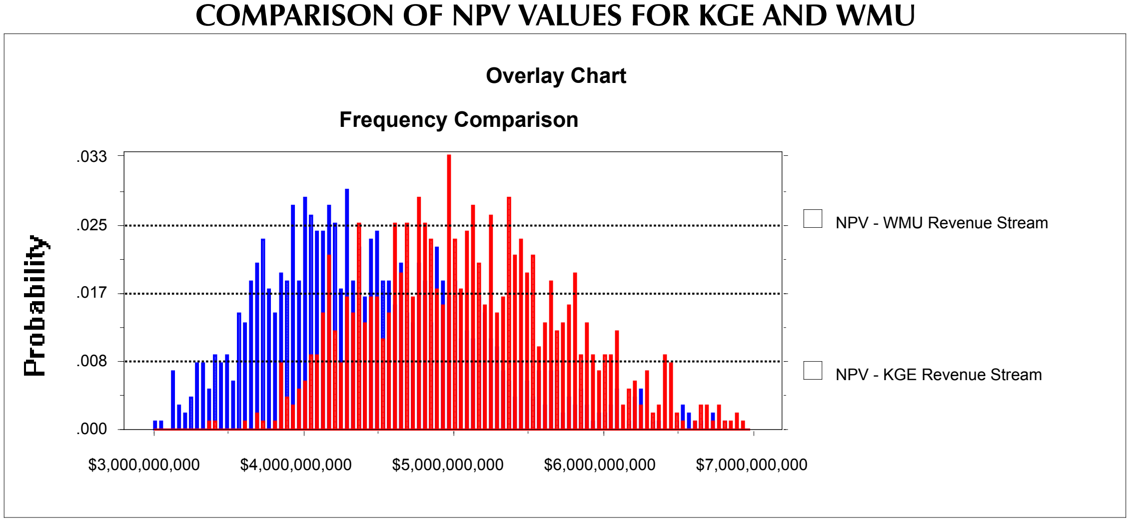


Extreme values are generated when the significant variables of gas price, inflation, and system demand are all relatively high or low over the study period.

CASE COMPARISON

To understand the risk potential of municipalization given variations in the study assumptions, distribution of possible NPV results for both cases have been overlaid in Figure 8-3 below.

Figure 8-3
COMPARISON OF NPV VALUES FOR KGE AND WMU

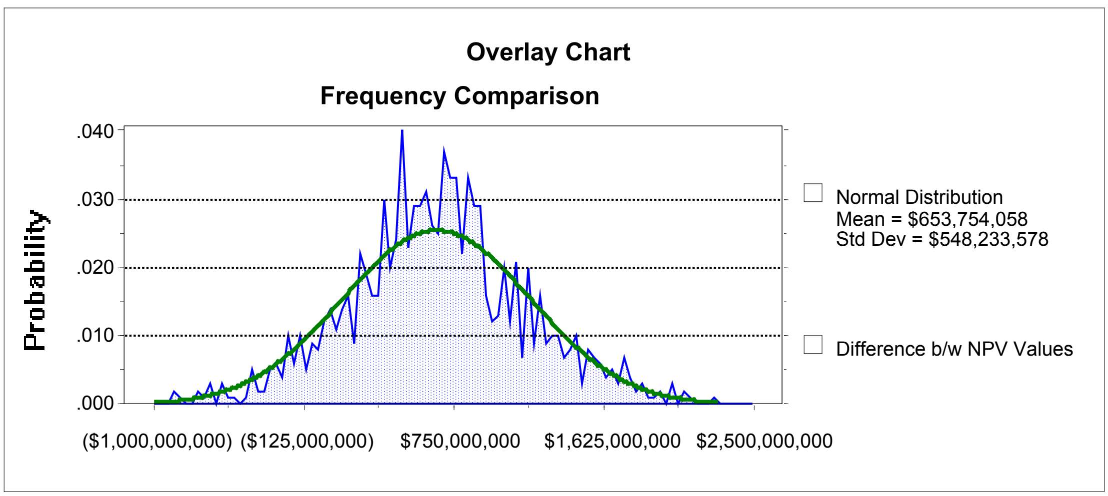


The above graph illustrates that the KGE case (in red) is less volatile than the WMU case but yields higher expected values for NPV. The probability of achieving NPV's greater than $5.0 billion are much greater in the KGE case than the WMU case. Because KGE relies primarily on existing generation assets to serve customer load, the utility is less sensitive to natural gas price swings, which heavily influence the market price for power. Therefore, KGE is less sensitive to changes in fuel than WMU. This factor is a primary influence on KGE's lower volatility.

Conversely, the WMU case (in blue) is more volatile than KGE, yet yields a greater potential of savings to the ratepayers (i.e. a lower NPV of revenue requirement). The probability of NPV's less than $5.0 billion is greater in the WMU case. For WMU, volatility is largely the result of purchasing power in the market.

The statistical results as described above are the results of evaluating 1,000 scenarios in which key variables are randomly generated (given their respective distribution profiles). In certain situations, the KGE case produces a lower NPV than the WMU case over the study period. This result occurs less than 20 percent of the time.

Figure 8-4
NPV OF SAVINGS (KGE-WMU)



NPV savings under the case can range from approximately $87.0 million to approximately $1.1 billion 66 percent of the time depending on market conditions, with the most likely savings of approximately $654 million (see Figure 8-4). Note that this value differs slightly from that discussed at the beginning of this section as the statistical analysis of the difference in NPV's yields a slightly different result than the statistical analysis of the NPV's themselves.

The primary assumption that results in lower KGE values relates to the price of natural gas and it's influence on the market price of power. Because KGE is somewhat insulated from market prices, (it has a resource mix of nuclear, coal, gas, and oil) gas prices have less of an impact on retail rates than in the WMU case. Therefore, when gas prices and corresponding market prices are high, retail rates under the municipalization case are higher. Based on our analysis, this threshold is approximately $50 per MWh. When market prices annually average $50 per MWH or higher, retail rates under municipalization are higher then in the KGE case.

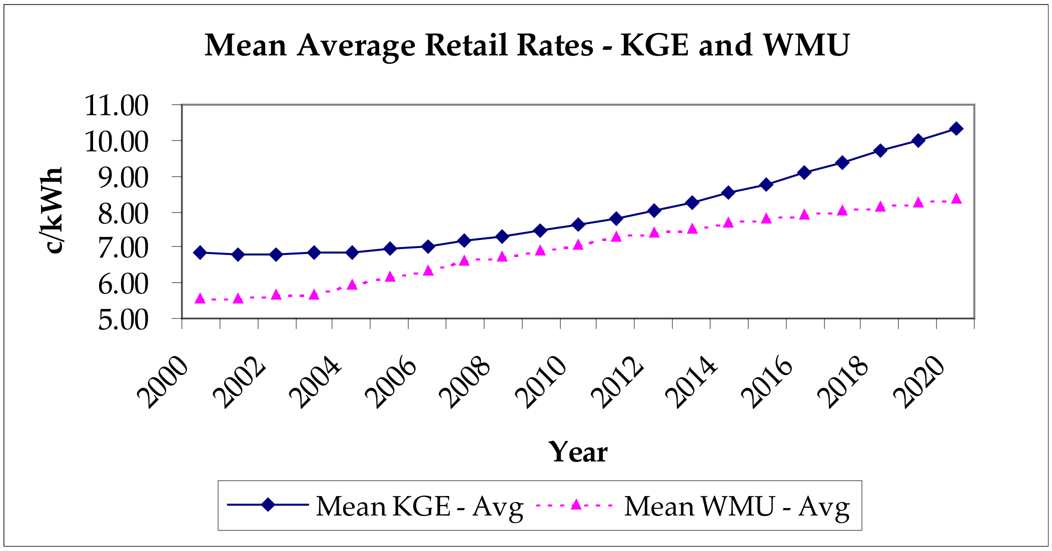
IMPACT ON RATES

In addition to the NPV analyses described above, average retail rates for both cases have been projected over the study period. The rates represent the total system revenue requirement divided by total system retail sales. Table 8-2 and Figure 8-5 below provide retail rates for each case over the study period.

Table 8-2
Mean Average Retail Rates for KGE and WMU

Year	KGE-Avg ¢/kWh	WMU-Avg ¢/kWh	Difference in Rates (KGE-WMU)¢/kWh	%Difference in Rates (KGE-WMU)
2000	68.68	55.54	13.14	-19.13%
2001	67.87	55.64	12.24	-18.03%
2002	67.77	56.53	11.24	-16.58%
2003	68.27	56.48	11.80	-17.28%
2004	68.51	59.71	8.80	-12.84%
2005	69.35	61.64	7.70	-11.11%
2006	70.43	63.21	7.22	-10.25%
2007	71.80	66.47	5.34	-7.43%
2008	72.96	67.53	5.43	-7.44%
2009	74.60	69.26	5.34	-7.16%
2010	76.53	70.98	5.56	-7.26%
2011	78.26	72.71	5.54	-7.08%
2012	80.54	73.97	6.57	-8.16%
2013	82.76	75.46	7.29	-8.81%
2014	85.15	76.83	8.32	-9.77%
2015	87.84	78.14	9.71	-11.05%
2016	90.79	79.36	11.43	-12.59%
2017	93.80	80.49	13.32	-14.20%
2018	96.88	81.53	15.35	-15.85%
2019	100.00	82.47	17.53	-17.53%
2020	103.23	83.47	19.76	-19.14%

Figure 8-5



As shown in the graph and table above, WMU average retail rates are projected to be between approximately 7 and 19 percent lower than KGE's average retail rates. Appendix B contains the revenue requirements underlying KGE's and WMU's retail rates (i.e., pro forma results).

CONCLUSION

It is expected that municipalization can save Wichita ratepayers approximately $654 million over the study period. Although the municipalization case may produce more volatile results, thus more volatile retail rates over the study period, in most cases, these rates will be equal to or lower than projected KGE rates.

CONCLUSIONS AND RECOMMENDED ACTIONS

The financial analyses comprising this Municipalization Feasibility Study indicates there is a reasonable expectation that the City could acquire the KGE distribution facilities within the City and operate a municipal electric utility at costs significantly lower than those costs expected under continued service from KGE. As described in sections earlier, the probability analyses quantifying outcomes when the uncertainty of significant variables used in the study are considered, the expected NPV of savings from municipal operation is approximately $654 million. The resulting retail rate levels are between 7 and 19 percent lower than under continued KGE operation.

These results alone are not sufficient to suggest that the City should proceed with initiating the operation of its existing municipal utility including the acquisition of KGE facilities through condemnation, or otherwise. The City must consider other, mainly qualitative issues, in order to determine whether additional steps towards municipalization should be pursued. This section provides a description of some of the other matters directly affecting the City's municipalization decision.

LENGTH OF TIME TO ACHIEVE

The City can expect WRI to vigorously resist any attempt to acquire its facilities to establish a municipal electric utility. Based upon Beck's experience in other municipalization efforts, the City can expect to be engaged in legal battles before the KCC and the FERC, as well as court proceedings challenging everything from its legal authority for acquiring the operating utility to the price it would have to pay for the facilities. Establishing legal title to the facilities will take years to achieve, and will be costly in terms of outside legal, engineering and financial experts.

Beck has included $5 million in the study to accommodate these costs, however it is difficult to predict the length of time necessary to achieve a satisfactory acquisition. For purposes of the economic analysis, it has been assumed the municipal utility begins operation at the termination of the KGE franchise in March 2002. It is unlikely this schedule is practical without KGE's cooperation.

As compared to the City's budget to pursue the municipalization effort, WRI's budget to oppose the City's efforts is effectively unlimited. It has been reported that WRI spent $60 million in its failed attempt to acquire Kansas City Power and Light. The City will have to seriously consider whether it wants to engage in a long, costly fight with WRI to achieve the municipal utility.

STATEWIDE UTILITY RESTRUCTURING

Another area of considerable uncertainty the City must consider is the statewide regulatory restructuring of the electric utility industry. This report was not intended to address future electric utility restructuring and its effect upon customers in a specific manner. Current assessments of the activity in Kansas in this regard are that no significant changes are expected to be addressed any time soon, in part due to the problems being experienced in other states that have proceeded with restructuring, particularly California.

Should restructuring proceed at a quicker pace in Kansas than currently anticipated, the City could find that certain of the financial benefits expected from municipalization would be achieved from the new established competitive market. Most significant of those would be access to the competitive wholesale market, at costs lower than current KGE costs, directly by customers inside Wichita or collectively through aggregation of customer loads by the City or other parties. Additionally, stranded investment costs would, in all probability, be addressed by any Kansas restructuring statutes, and the resulting stranded investment costs born by citizens in Wichita could be significantly lower than those quantified in this study.

That said, restructuring of the utility industry in Kansas, under any reasonable basis such as has been done in other states and jurisdictions, would not render municipalization a bad idea – that is, Wichita citizens would not likely be worse off if the municipal utility were formed ahead of state wide utility restructuring. In fact, municipal utilities have generally been exempt from many of the provisions of restructuring. It simply means that at least some of the expected rate benefits from municipalization *could potentially be* achieved without actually forming a municipal electric utility.

RATE LITIGATION

The forecast of KGE rate levels has been developed consistent with WRI's past and continued insistence upon revenue requirement development for KPL and KGE as separate and distinct divisions for ratemaking purposes. The City is vigorously challenging the inappropriate rates which result from WRI's position on this matter in light of its operation as a single, integrated electric utility. Should the City be successful at FERC or the KCC with arguments that ultimately improve the rate disparity which currently exists, future KGE rate levels could be lower, at least in the short term, than the levels used in this study.

The effect on the benefits of municipalization under a combined WRI system were not quantified, as the development of a forecast of combined WRI revenue requirements was not a part of this study. However, over the 20 year study period, the combined WRI revenue requirement would not result in retail rates significantly different than those developed for KGE. This is the result of several factors:

- KPL's revenue requirement will increase significantly due to new units coming online in 2000 and 2001.
- Wolf Creek costs will continue to decline due to depreciation of the plant in the future.
- Both KGE and KPL will, over a 20-year time horizon, require new capacity at the then current state of technology for new generation, driving both utilities to similar future costs.

In the short term however, rate parity improvements achievable through regulatory litigation could result in achieving some of the benefits attainable from municipalization.

SYNERGIES WITH OTHER CITY ACTIVITIES

No consideration was given in this study to benefits, or synergies, which the City might reasonably achieve related to other operations such as the water or wastewater systems, or billing, accounting and meter reading. Further, operation of an electric distribution system offers significant opportunity to become involved in communications, or other activities, on behalf of City government or other entities such as county or state government, schools and universities as well as citizens. The City should consider whether these, or other potential activities, influence its decision to proceed with municipalization.

These are just a few obvious considerations which should be given before a decision to proceed with municipalization is made. If, in fact, the City decides to proceed further, a number of activities must be engaged before a definitive decision to municipalize can be made. Following are some key efforts which would need to be undertaken before a final decision is reached.

FURTHER ACTION ITEMS

Before the City can determine whether the implementation of an operating electric utility should be accomplished, it will need to get more definition of the associated costs. The action items, at a minimum, that will need to be addressed are discussed briefly below.

NEGOTIATIONS WITH WRI

The City should begin discussions with WRI regarding the potential to negotiate a purchase of KGE facilities. While WRI's cooperation is not expected, it is certainly possible, due to WRI's public statements that it desires to sell or merge its entire system with another entity, that the company would entertain an amicable transfer of its assets.

SYSTEM INVENTORY

A detailed field inventory will need to be prepared of facilities within Wichita. This effort could be streamlined based upon access to, and quality of, KGE's records. However, it is quite likely that an inventory will require a pole-by-pole, facility-by-facility itemization of assets. This level of detail is required to place a valuation on the assets which would be credible in condemnation proceedings.

SEVERANCE DESIGN

A detailed design and physical severance plan will need to be developed in order to gain confidence in the costs of separating the facilities within Wichita from the remaining KGE system. This design plan would provide the basis for actual physical severance implementation at such time as the transfer would take place.

POWER SUPPLY PROPOSALS

As part of the Feasibility Study, a number of potential suppliers were contacted. There is significant interest in supplying wholesale power to Wichita. A formal RFP will need to be developed, issued, bids received and evaluated in order to firm up the municipal power supply costs before any final decision to municipalize is made.

FERC STRANDED COST RULING

The City should launch a stranded cost proceeding at FERC in connection with a request for wholesale transmission service to the municipal utility. This proceeding will better identify whether stranded costs exist, and if so the amount to which the City will be exposed if it decides to operate its municipal utility.

ORGANIZATIONAL DEVELOPMENT

The City should begin the examination of how it would develop the operating organization for the utility. Such matters as management, policy and decision making board, level of outsourcing are matters which need to be addressed in order to firm up utility operations costs.

At any time during the process of investigating these matters, the City can make a determination to take an "off ramp" and cease municipalization efforts. If initial indications from the above activities indicate a desire to proceed, then the City should engage financial, legal and engineering experts to develop a "Strategic Plan for Implementation" of the municipal utility operation. Once developed, this plan would guide the overall process towards actual acquisition of assets and operation of the utility.

APPENDIX A
KGE STRANDED INVESTMENT CALCULATION

WINSTON & STRAWN

35 WEST WACKER DRIVE
CHICAGO, ILLINOIS 60601-9703

1400 L STREET, N.W.
WASHINGTON, D.C. 20005-3502

200 PARK AVENUE
NEW YORK, NEW YORK 10166-4193

43 RUE DU RHONE
12O. GENEVA, SWITZERLAND

21 AVENUE VICTOR HUGO
75116 PARIS, FRANCE

444 SOUTH FLOWER STREET
LOS ANGELES, CALIFORNIA 90071-2911

(202) 371-5700
FACSIMILE (202) 371'5922
FACSIMILE (202) 371-5950
www.winston com

DONALD K. DANKNER
(202) 371-5778

August 14, 2000

VIA HAND DELIVERY

Timothy R. Corrigan
R.W. Beck, Inc.
1125 Seventeenth Street
Suite 1900
Denver, Colorado **80202**

Gregg D. Ottinger
Duncan & Allen
1575 Eye Streets N.W.
Suite 300
Washington, D.C. 20005

RE: Stranded Cost Estimate

Dear Messrs. Corrigan and Ottinger:

This letter responds to Mr. Ottinger's July 14, 2000 letter requesting an estimate of the stranded cost charges the City of Wichita ("Wichita" or the "City") would owe Kansas Gas and Electric Company ("KGE") under FERC Order No. 888's "revenues lost" formula, assuming Wichita were to establish a municipal electric system to provide distribution service to customers located in the City and adjacent areas effective March 1, 2002.

As shown in the attached supporting materials, KGE estimates that such a municipalization would give rise to a total of approximately $1.63 billion in stranded costs to be recovered under Wichita's preferred monthly surcharge method over the period commencing March 1, 2002 and ending December 31, 2015. Although Order No. 888 provides that it may be appropriate to subtract distribution system related revenues from the Revenue Stream Estimate component of the formula, KGE has not done so here because the City has provided no details on how the City intends to establish a municipal electric system to provide distribution service. Further, if the City acquires any portion of KGE's distribution system, it must fully compensate KGE as provided under Kansas law.

This stranded cost estimate is preliminary, and KGE reserves the right to modify it to reflect, *inter alia,* changes in Wichita's municipalization plans, changes to KGE's costs, or changes to market conditions that may occur between now and any filing with FERC regarding Wichita's contemplated municipalization.

Sincerely,

Donald K. Dankner

Enclosures

cc: Martin J. Bregman

ATTACHMENT A

CALCULATION OF MONTHLY STRANDED COST CHARGE

Table A-1
Annual Stranded Costs and Monthly Stranded Cost **Charge**
2002-2015

Y ar e	Average Monthly RSE	Average Monthly CMVE	Monthly Charge	Annual Stranded Cost Charge
2002'	$ 28,O58,454	$ 16,710,860	$ 11,347,594	$ 113,475.940
2003	$ 28,058,454	$ 16,710,860	$ 11,347,594	$ 136,171,128
2004	$ 28,058,454	$ 16,710,860	$ 11,347,594	$ 136,171,128
2005	$ 28,058,454	$ 17,011,656	$ 11,046,798	$ 132,561,576
2006	5 28,058,454	$ 17,317,866	$ 10,740,588	$ 128,887,056
2007	$ 28,058,454	$ 17,629,587	$ 10,428,867	$ 125,146,404
2008	$ 28,058,454	$ 17,946,920	$ 10,111,534	$ 121,338,408
2009	$ 28,058,454	$ 18,269,964	$ 9,788,490	$ 117,461,880
2010	$ 28,058,454	$ 18,598,824	$ 9,459,630	$ 113,515,560
2011	$ 28,058,454	$ 18,933,602	$ 9,124,852	$ 109,498,224
2012	$ 28,058,454	$ 19,274,407	$ 8,784,047	$ 105,408,564
2013	$ 28,058,454	$ 19,621,347	$ 8,437,107	$ 101,245,284
2014	$ 28,058,454	$ 19,974,531	$ 8,083,923	$ 97,007,076
2015	$ 28,058,454	$ 20,334,072	$ 7,724,382	$ 92,692,584
Total Stranded Cost **Charge**				

' Ten months, per Wichita's request.

ATTACHMENT B

REASONABLE EXPECTATION PERIOD (L)

KGE has provided retail electric service to its customers in the "Wichita areas for over 90 years, and has an obligation to continue to serve those customers under Kansas law. If it was not for FERC's Order No. 888, KGE's expectation is that it would continue to serve Wichita in perpetuity. For purposes of this analysis, KGE has conservatively assumed that a hypothetical municipalization on March 1, 2002 would give rise to a stranded cost recovery period continuing **through December** 31, 2015.

BASIS FOR EXPECTATION

- The area that Wichita is considering to municipalize is, and has been, an integral part of KGE's retail load for over 90 years.
- These loads currently constitute approximately 65% of KGE's total customer base. It is manifest that the company has had to plan its resources in contemplation of a continuing requirement to serve these customers.
- Under Kansas statutes, KGE has had, and continues to have, a continuing obligation to serve the retail customers in its certificated territory including the Wichita area. There is no time limit on this obligation, and KGE may not discontinue service absent express direction from the Kansas Corporation Commission ("KCC").
- The historic renewal period for an electric service franchise is 20 years. In planning and making generation investments, KGE prudently has had to plan for at least one further renewal of the franchise.

In applying FERC's stranded cost formula herein, KGE has used the load data for the City of Wichita and the unincorporated area within three miles of the City because this data approximates the loads identified in the City's stranded cost request. KGE refers to this as the "Wichita area" throughout.

· KGE's franchise to serve the City has been renewed each time that it has expired.

1

LENGTH OF WICHITA FRANCHISESI
FOR ELECTRIC UTILITY SERVICES |

1907 - 30 years

1921 - 35 years

1947 - 20 years

1964 - 20 years

1 1982 - 20 years

o There has never been an electric municipalization in Kansas on the scale contemplated by Wichita, and to KGE's knowledge, there has been only one minor electric municipalization in Kansas in the last century, a 1970 municipalization by the City of Kiowa (pop. 1,000) of electric distribution plant valued at the time at approximately $350,000.

· KGE has pursued long-lived investments in plant and equipment necessary to meet its obligation to serve Wichita into the future. For example, the Wolf Creek Nuclear plant, which was planned to serve anticipated load growth in the Wichita area, was placed in service in 1985, with an expected life of 40 years (i.e., until 2025).

KGE continues to make capital investments to add new plant and maintain existing facilities to meet its obligation to serve the Wichita area. Over the last ten years, KGE has invested $224 million in new capital additions to maintain and extend the lives of its generating plants. Most recently, KGE restarted the 67 MW Neosho plant near Parsons, Kansas to meet Wichita's growing power needs.

The City of Wichita still has not given notice to KGE that would permit KGE to cease planning and making investments to serve the Wichita area's retail customers.

Under Kansas law, KGE remains under an obligation to serve these customers until a municipal utility actually is formed and assumes the responsibility to provide service.

For customers located outside the city limits, KCC permission to redraw the service territory boundaries and to authorize the City to serve within such territories would be needed.

Wichita has not as yet completed the necessary steps to form a municipal utility. In view of the costs of doing so, and other impediments, there is, even today, no assurance or even basis for likelihood that it will do so.

Wichita public of ficials have stated they are merely investigating the feasibility of municipalizing, and have made no determination to pursue this course.

Public statements by Wichita officials about the possibility of municipalization have been in the context of a broader campaign to gain rate equalization between KGE and KPL and do not constitute notice.

The City of Wichita studied a limited municipalization of city street lighting services in 1987 and abandoned the effort because its consultants determined it was uneconomic.

ATTACHMENT

REVENUE STREAM ESTIMATE (RSE)

The calculation of RSE, which is described in this Attachment C, is based on the dollars of revenue billed to the retail customers that, collectively, would turn into a wholesale customer, less transmission revenues that KGE would continue to receive Tom the municipal utility. Although Order No. 888 notes that it may be appropriate to subtract distribution system related revenues from the RSE (Order No. 888, III FERC Stats. & Regs. 11 31,036, at 31,839 n.863 (1996)), KGE has not done so here because Wichita has not provided any details concerning how it intends to establish a municipal electric system to provide distribution service.

Since new retail rates have gone into effect in the last three years, only one year of billing data was used to calculate the RSE. Data for calendar year 1999 was used in this analysis Amounts billed to customers for franchise tax, state sales tax and county sales tax have been excluded.

Total KGE Retail Revenues Billed in 1999 to Wichita Area Customers. Total KGE retail revenues billed in 1999 to Wichita area customers are represented in Table C-1.

Table C-1
Total KGE Retail Revenue Billed in 1999 to Wichita Area Customers

Revenue Class	kWh	Customer Charge	Energy Charge	Demand Charge	Pole Charge	LMR Charge	LMR Credit	Revenue Before Taxes
Residential	1,555,505 856	$13 892,670	$119,445 221					$133,337,891
Commercial & Industrial	4,039,044,546	$2,134,933	$163,450,170	$50,266,383		$4,662	($ 156,773)	$215,699,375
Street Lighting	20,315,775	$2,895 330	$305,750					$3,201,080
PAL'	8,897 044	$2.690	$1 626 083		$35 351			$1,664 124
Total Retail	5,623,763,221	$18,925,623	$284,827,224	$50,266,383	$35,351	$4,662	($156,773)	$353,902,470

' PAL is private area lighting. This service spans a range of customer classes.

This table reflects data for the twelve monthly billing cycles beginning in January 1999 and ending in December 1999. The energy measured in kWh reflects the amounts as measured or estimated at customer meters.

Adjustment for Anticipated Transmission Revenues. To estimate the amount that customers in the Wichita area would have paid for transmission service under the OATT, the required billing unit information for the proposed Wichita area municipal utility computation of a pro forma OATT invoice for each month of 1999 was developed. This requires monthly energy and coincident peak demand data for the load of the Wichita area and monthly coincident peak demand data for the transmission system. The load data for **the Wichita area was** developed from a combination of substation metered load data, billing load data and load research. The monthly coincident peak loads for the transmission system was developed from metered data.

The monthly energy data for the Wichita area were used as pro forma billing units to calculate the 1999 pro forma transmission charges under the OATT and are given in Table C-2.

Table C-3

Monthly Coincident Peak Loads (kW) of the Wichita Area in 1998 & 1999

Month	1999	1998
January	850,369	815,793
February	828,208	818,490
March	664,516	669,341
April	735,962	689,713
May	740,106	730,827
June	897,056	948,130
July	948,800	1,033,820
August	1,165,985	1 032,136
September	1,337,193	1,388,016
October	863,154	968,478
November	730,800	714,209
December	738,565	726,178

The load data for the transmission system that are used to calculate the Wichita area's load ratio share of the total transmission load on the transmission system are given in Table C-4. This data includes the load of the Wichita area. This information, once developed, provides a sufficient basis for calculating the Wichita area billing units for the OATT and computing the **monthly pro forma bills** for transmission service. The AGE 1998 monthly system peaks were calculated by developing a factor based on the 1999 monthly system peaks of KGE's and KPL's individual systems and multiplying this factor by the combined 1998 system peaks for KGE's and KPL's individual systems.

[2] Derived from 1998 monthly energy transmitted by using the 1999 monthly load factor

Table C-4
1998 & 1999 Transmission System Monthly Peak Loads

Month	**1999** **Monthly Non-System** Coincident Peak Load	**1999** Transmission Coincident Peak Load	**1999** Transmission System Coincident Peak Load Divided by Non- Coincident Peak Load	**1998** Monthly Non- Coincident Peak Load4Peak Loads	**1998** Estimated Transmission System Coincident
Col	(1)	(2)	(3)	(4)	(5)
Jan	3165	3243	1.025	2996	3070
1 Feb	2827	2896	1.024	2833	2902
Mar	2771	2820	1.018	2983	3036
Apr	2655	2732	1.029	2607	2683
May	2949	3016	1.023	3902	3991
Jun	4031	4000	0.992	4413	4379
Jul	4698	4804	1.023	4565	4668
Aug	4771	4774	1.001	4578	4581
Sep	4240	4332	1.022	4536	4634
Oct	3083	3171	1.029	2871	2953
Nov	2805	2883	1.028	2841	2920
Dec	3023	3099	1.025	3251	3333

The peak load data used in the OATT is the 12-month rolling average coincident peak loads for both the transmission customer and the transmission system. Accordingly, to calculate transmission charges for 1999, the monthly peak loads from 1998 and 1999 need to be transformed to such 12-month rolling averages. These data are shown in Table C-5.

3 1999 FERC Form 1, Page 401 b.

4 1998 FERC Form 1, Page 401 b.

5 The 1998 monthly system coincident peaks (Column 5) were derived by dividing the 1999 monthly coincident peaks (Column 2) by the monthly noll-coincident peaks (Column 1), and multiplying the resulting ratios for each month (Column 3) by the 1998 monthly non-coincident peaks (Column 4).

Table C-5
12-Month Rolling Average Coincident Peak Loads for 1999 of
the Wichita Area and the Transmission System
and Resulting Load Ratio Share

	12-Month Rolling Average Coincident Peak Load (kW)		
Month	Wichita Area	Transmission System	Resulting Load Ratio Share
January	880,809	3,765,100	23.39%
February	881,619	3,764,588	23.42°/~
March	881,217	3,746,609	23.52%
April	885,071	3,750,725	23.60%
May	885,844	3,669,504	24.14%
June	881,588	3,637,915	24.23%
July	874,503	3,649,249	23.96%
August	885,657	3,665,342	24.16%
September	881,422	3,640,140	24.21%
October	872,645	3,658,311	23.85%
November	874,027	3,655,228	23.91%
December	875,059	3,635,750	24.07%

The resulting pro forma revenues that would have been received during 1999 from the Wichita area are shown in Table C-6.

Table C-6
1999 Pro Forma OATT Revenues from the Wichita Area

Component of OATT |	**For Customers in the Specified Area**
Firm Network Transmission Service Revenue	**$15,8**
Ancillary Services Revenues	
Schedule 1: Scheduling System and Dispatch Service	$910,494
Schedule 2: Reactive Power and Voltage Control	$416,782
Schedule 3: Regulation and Frequency Response	$0
Schedule 4: Energy Imbalance Service	$0
Schedule 5: Spinning reserve	$0
Schedule 6: Supplemental Reserve Service	$0
Total Ancillary Services	**$1,327,276**
Total OATT Revenue ~=	**$17,201,025**

The total 1999 transmission adjustment calculated from the OATT is $17~201,025. When subtracted from a total revenue of $353,902,470, this yields an RSE of $33G,701,445. Dividing by twelve gives an average monthly RSE of $28,058,454.

6 KGE has assumed Wichita will self-supply ancillary service schedules 3 through 6 based on Wichita's request for proposals requesting vendors to submit bids for these services.

ATTACHMENT D

COMPETITIVE MARKET VALUE ESTIMATE (CMVE)

The measure of CMVE is $200,530,323 per year through the end of calendar year 2004, with slight annual increases in CMVE thereafter. This measure is given by the product of the market value of released capacity and associated energy ($34.38/MWh) and the annual load of the Wichita area during 1999 (5,832,761 MWh). The amount of capacity required to serve this load was 1,360 MW of KGE's total 1999 capacity of 2,422 MEW The following describes how the market value of released capacity and associated energy is calculated.

The long run equilibrium price of released capacity and associated energy ($34.38/MW.) is derived from published measures of North SPP spot market prices for energy during peak al ~ off-peak periods, and the cost of building and operating a combustion turbine (CT) generate.- g unit. The CT would operate when the North SPP spot market price exceeds the variable cost of operating the CT. A weighted average of these components is calculated, where the weights are the 1999 loads for the Wichita area. Weighted averages are calculated separately using spot market prices for Cinergy and Entergy for comparison with the results obtained using North SPP prices.

The capital and operating costs of a new CT are based on the actual costs and operating characteristics of two new CTs recently installed at the Gordon Evans Energy Center.2 The levelized annual carrying charge of these CTs, including a 15 percent reserve margin, is $81,806.34/MW.

The variable cost of a CT is $34.04/MWh, and is composed of energy costs and variable O&M costs. Variable O&M is set at $3.42/MWh, which is the average variable O&M costs for

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This is the actual peak load for the Wichita area. The peak load number given in Table C-3 is that which is coincident with the transmission **system peak** load.

2 The information used here is taken from a filing at FERC by Westar Generating II, Inc., to establish rates, terms, and conditions for the sale of electric capacity and energy by Westar to Western Resources, Inc. *See Westar Generating 11, Inc.,* Docket No. ER00-9348-000, Attachment 3.

KGE's other gas-fired units and, based on data obtained from KPL, KPL's other gas-fired units. The energy cost is $30.62/MWh, which is based on a gas price of $2.82/Mcf and a heat rate of 10,857 Btu/kWh. The gas price is the average Henry Hub price during the 12 months from July 1999 through June 2000 (from *Natural Gas Week),* plus a $0.02/Mcf adjustment for the delivered cost of gas in Kansas (to reflect the historical price differential between the Henry Hub and gas delivered to gas fired-plants in Kansas).

The capital cost of a CT on a per-MWh basis is determined by spreading the annual carrying charge over the number of hours the CT will operate. As noted, the CT will operate when the spot market price exceeds the variable cost of the CT. Spot market prices are an index of the average price during the 16 peak hours of each weekday in the North SPP, Cinergy, and Entergy. When North SPP prices are used, the CT will operate during 66 days for a total of 1,056 hours; when Cinergy prices are used the CT will operate 61 days (976 hours); and when Entergy prices are used the CT will operate 89 days (1,424 hours). Thus, the capital cost is $77.47/MWh when North SPP prices are used; $83.82/MWh when Cinergy prices are used; and $57.45/MWh when Entergy prices are used.

Combining variable costs and capital costs, the total cost of a CT is $111.51/MWh with North SPP prices, $117.86/MWh with Cinergy prices, and $91.49/MWh with Entergy prices. The total cost of a CT is multiplied by the load during the 16 peak hours in each weekday in which the spot price exceeds the variable cost of a CT to obtain the value of the released capacity and associated energy during these periods. This is one component used to determine the weighted average of the annual value of the released capacity and associated energy.

Spot market prices (obtained from *Power Markets Week)* are used to value three additional components of the weighted average value of the released capacity and associated energy: (i) prices during the 16 peak hours of each weekday when the spot price is less than the variable cost of a CT; (ii) prices during the eight off-peak hours of each weekday; and (iii) prices during the 48 hours on weekends.

During the 16 peak hours of each weekday when the spot price is less than the variable cost of a CT, the load on each such day is multiplied by the market price for that day, and the product for all such days is summed to get the total value of released capacity and energy during these periods. This is the second component of the weighted average value of the released capacity and associated energy.

The value of released capacity and associated energy during the eight off-peak hours of each weekday is obtained using the midpoint of the daily average off-peak prices published by *Power Markets Week* for the North SPP. Similar off-peak prices are not published for Cinergy and Entergy, so North SPP off-peak prices are used to value off-peak loads in these markets. As **above, the load** during the eight off-peak weekday hours was multiplied by the midpoint of the **North SPP** off-peak price to give the third component of the weighted average value of the released capacity and associated energy.

The value of released capacity and associated energy used during weekends (and weekday holidays) is determined in relation to weekday peak prices, following a procedure used for pricing contract offers. The procedure sets average weekend prices in proportion to average weekday peak prices, where the factor of proportionality varies by month. For October through April the factor is 0.75, for May it is 0.7, for June it is 0.45, for July and August it is 0.33, and for September it is 0.65. For example, for a given weekend in July, the average of the peak prices for the preceding live weekdays is multiplied by 0.33 to give the weekend price.[3] Weekend prices calculated this way are then multiplied by the aggregate amount of load for each weekend to give the fourth component of the weighted average value of the released capacity and associated energy.

Applying the foregoing procedure to spot market prices in the North SPP from July 1, 1999 through June 30, 2000, the market value of released capacity and associated energy is $34.38/MWh. When Cinergy prices are used, the value of the released capacity and associated energy is $34.77/MWh. When Entergy prices are used, the value is $36.68/MWh.

The difference between the price in the North SPP and the prices in Cinergy and Entergy may be attributed to transmission costs and line losses. Hence, the estimated market values

[3] All daily prices in the preceding week are used in the average, not just those prices below the variable cost of a CT.

based on Cinergy and Entergy spot market prices corroborate the estimated market value based on North SPP spot market prices.

The estimated market value of released capacity and energy ($34.38/MWh) applies to the period that lasts through December 31, 2004. After that time, the price will increase by 1.8 **percent per year.** Estimates of the increased CMVE for each year after 2004 are set forth in Table A-1 in Attachment A.

APPENDIX B
KGE AND WICHITA PROJECTED FINANCIAL RESULTS

Projected Operating Results
Wichita Municipal System

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	Historical	Historical / Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
Number of Customers													
Residential	154,104	156,108	153,006	156,406	159,948	163,348	166,819	170,290	174,752	179,357	183,819	188,564	193,431
Commercial	15,572	16,029	16,254	16,616	16,992	17,353	17,722	18,090	18,565	19,054	19,528	20,032	20,549
Industrial	924	949	945	966	988	1,009	1,030	1,052	1,079	1,108	1,135	1,164	1,194
Public Street & Highway Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Retail	170,600	173,086	170,205	173,987	177,927	181,709	185,571	189,432	194,396	199,518	204,482	209,760	215,175
Percent Growth	N/A	1.5%	-1.7%	2.2%	2.3%	2.1%	2.1%	2.1%	2.6%	2.6%	2.5%	2.6%	2.6%
Load													
Usage per Customer		2,499	970										
Usage Per Customer (MWH/Customer)													
Residential Sales		10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Commercial Sales		107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4
Industrial Sales		2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3
Public Street & Highway Lighting		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		-											
MWH Sales													
Residential Sales	1,654,650	1,544,921	1,578,538	1,613,616	1,650,156	1,685,235	1,721,045	1,756,854	1,802,895	1,850,397	1,896,438	1,945,388	1,995,602
Commercial Sales	1,685,420	1,708,925	1,746,111	1,784,913	1,825,333	1,864,135	1,903,746	1,943,357	1,994,285	2,046,830	2,097,758	2,151,905	2,207,450
Industrial Sales	2,430,010	2,371,316	2,422,915	2,476,758	2,532,844	2,586,687	2,641,651	2,696,615	2,767,284	2,840,195	2,910,864	2,985,999	3,063,073
Public Street & Highway Lighting	28,909	28,504	29,124	29,771	30,445	31,093	31,753	32,414	33,263	34,140	34,989	35,892	36,819
Total Retail Sales	5,798,989	5,653,666	5,776,688	5,905,059	6,038,779	6,167,149	6,298,195	6,429,240	6,597,727	6,771,562	6,940,049	7,119,185	7,302,944
% Growth		-3%	2.18%	2.22%	2.26%	2.13%	2.12%	2.08%	2.62%	2.63%	2.49%	2.58%	2.58%
System Loss Factor			5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
System Losses			301,532	308,233	315,213	321,914	328,754	335,594	344,389	353,463	362,258	371,608	381,200
NEFL		5,948,777	6,078,220	6,213,292	6,353,991	6,489,063	6,626,949	6,764,834	6,942,116	7,125,025	7,302,306	7,490,793	7,684,144
Purchased Power													
NEFL		5,948,777	6,078,220	6,213,292	6,353,991	6,489,063	6,626,949	6,764,834	6,942,116	7,125,025	7,302,306	7,490,793	7,684,144
All In Energy Price - $/MWH		33.46	34.05	34.64	35.43	36.76	38.58	40.79	42.14	44.70	46.11	47.56	49.02
Purchased Power Cost - Including Trans Wheeling		199,044,249	206,959,682	215,222,728	225,121,139	238,533,868	255,645,947	275,966,422	292,517,031	318,453,163	336,723,428	356,276,959	376,667,734
Less Transmission Wheeling			13,893,075	14,571,057	15,288,444	16,003,778	16,752,437	17,528,527	18,437,582	19,396,456	20,376,046	21,424,539	22,526,986
Purchased Power Cost - w/o Trans Wheeling		199,044,249	193,066,607	200,651,671	209,832,695	222,530,090	238,893,510	258,437,896	274,079,449	299,056,707	316,347,382	334,852,420	354,140,748
Plant in Service													
EOY Balances													
Other Plant - Premium			181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533
Distribution Plant			336,685,295	344,035,533	352,069,619	360,154,992	368,807,602	377,878,273	390,104,042	403,327,385	416,763,099	431,738,189	447,842,028
General Plant			8,385,295	8,568,356	8,768,449	8,969,819	9,185,316	9,411,225	9,715,713	10,045,046	10,379,668	10,752,630	11,153,703
Total Electric Plant			527,038,124	352,603,889	360,838,068	369,124,810	377,992,918	387,289,498	399,819,755	413,372,431	427,142,768	442,490,818	458,995,731
Accumulated Depreciation (EOY)													
Other Plant			6,065,584	12,131,169	18,196,753	24,262,338	30,327,922	36,393,507	42,459,091	48,524,675	54,590,260	60,655,844	66,721,429
Distribution Plant			8,190,250	16,559,303	25,123,794	33,884,971	42,856,633	52,048,949	61,538,670	71,350,065	81,488,298	91,990,817	102,885,080
General Plant			246,515	498,412	756,191	1,019,890	1,289,924	1,566,600	1,852,227	2,147,536	2,452,683	2,768,794	3,096,696
Total Electric Plant			14,502,350	29,188,884	44,076,738	59,167,199	74,474,479	90,009,055	105,849,989	122,022,277	138,531,241	155,415,455	172,703,205
Net Plant In Service (EOY)													
Other Plant			175,901,949	169,836,364	163,770,780	157,705,195	151,639,611	145,574,026	139,508,442	133,442,858	127,377,273	121,311,689	115,246,104
Distribution Plant			328,495,045	327,476,230	326,945,825	326,270,020	325,950,969	325,829,324	328,565,372	331,977,321	335,274,801	339,747,371	344,956,947
General Plant			8,138,780	8,069,945	8,012,258	7,949,929	7,895,391	7,844,625	7,863,486	7,897,510	7,926,985	7,983,836	8,057,007
Total Electric Plant			512,535,774	505,382,538	498,728,863	491,925,144	485,485,971	479,247,975	475,937,299	473,317,688	470,579,060	469,042,896	468,260,059
Average Balance													
Other Plant			175,901,949	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533
Distribution Plant			328,495,045	340,360,414	348,052,576	356,112,306	364,481,297	373,342,938	383,991,158	396,715,714	410,045,242	424,250,644	439,790,108
General Plant			8,138,780	8,476,826	8,668,403	8,869,134	9,077,567	9,298,270	9,563,469	9,880,379	10,212,357	10,566,149	10,953,166
Total Electric Plant			512,535,774	530,804,773	538,688,512	546,948,972	555,526,397	564,608,741	575,522,159	588,563,626	602,225,132	616,784,326	632,710,807
Yearly Net Additions (Renewals & Replacements)													
Other			0	0	0	0	0	0	0	0	0	0	0
Distribution Plant			0	7,350,238	8,034,087	8,085,372	8,652,610	9,070,671	12,225,769	13,223,343	13,435,714	14,975,089	16,103,839
General Plant			0	183,061	200,092	201,370	215,497	225,909	304,488	329,333	334,622	372,961	401,073
Total Electric Plant			0	7,533,298	8,234,179	8,286,742	8,868,107	9,296,580	12,530,257	13,552,676	13,770,336	15,348,051	16,504,913
Depreciation ($)													
Other Plant			6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584
Distribution Plant			8,190,250	8,369,053	8,564,491	8,761,177	8,971,662	9,192,316	9,489,722	9,811,394	10,138,233	10,502,519	10,894,263
General Plant			246,515	251,897	257,779	263,699	270,034	276,676	285,627	295,309	305,147	316,111	327,902
Total Electric Plant			14,502,350	14,686,534	14,887,855	15,090,461	15,307,280	15,534,576	15,840,933	16,172,288	16,508,964	16,884,215	17,287,750

Revenue Requirement

			1998 Historical	1999 Historical / Projected	2000 Projected	2001 Projected	2002 Projected	2003 Projected	2004 Projected	2005 Projected	2006 Projected	2007 Projected	2008 Projected	2009 Projected	2010 Projected
	Operations & Maintenance Expense														
	Purchased Power				193,066,607	200,651,671	209,832,695	222,530,090	238,893,510	258,437,896	274,079,449	299,056,707	316,347,382	334,852,420	354,140,748
	Purchased Power - $/MWH Sold				33.42	33.98	34.75	36.08	37.93	40.20	41.54	44.16	45.58	47.04	48.49
	Transmission				13,893,075	14,571,057	15,288,444	16,003,778	16,752,437	17,528,527	18,437,582	19,396,456	20,376,046	21,424,539	22,526,986
	Distribution				15,024,557	14,685,058	14,344,900	13,975,557	14,311,315	14,663,296	15,137,708	15,650,831	16,172,194	16,753,292	17,378,190
	General				15,024,557	14,685,058	14,344,900	13,975,557	14,311,315	14,663,296	15,137,708	15,650,831	16,172,194	16,753,292	17,378,190
	Total O&M				237,008,796	244,592,844	253,810,940	266,484,982	284,268,577	305,293,015	322,792,447	349,754,825	369,067,816	389,783,543	411,424,113
	Debt Service				61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724
	Debt Service Coverage Ratio				1.00	1.14	1.16	1.17	1.20	1.22	1.26	1.31	1.28	1.32	1.34
Reset	Additional Funding of Reserves				-	1,196,325	1,535,275	2,172,940	3,289,490	4,038,333	3,785,489	5,469,468	3,322,618	4,346,220	4,282,239
Reset	Less Interest Earnings				(5,442,140)	(5,744,541)	(5,815,163)	(5,786,529)	(5,934,556)	(6,116,281)	(6,286,628)	(6,532,754)	(6,682,272)	(6,877,852)	(7,070,553)
	Capital Paid From Current Earnings				0	7,533,298	8,234,179	8,286,742	8,868,107	9,296,580	12,530,257	13,552,676	13,770,336	15,348,051	16,504,913
	Sub-Total Revenue Requirment				293,504,381	309,515,651	319,702,955	333,095,859	352,429,343	374,449,372	394,759,289	424,181,939	441,416,222	464,537,686	487,078,437
	Additional Requriements to Meet Debt Service Coverage Minimun				12,387,545	3,657,922	2,618,091	1,927,863	229,948	-	-	-	-	-	-
	Sub-Total Revenue Requirment				305,891,926	313,173,572	322,321,046	335,023,722	352,659,290	374,449,372	394,759,289	424,181,939	441,416,222	464,537,686	487,078,437
	Debt Service Coverage Ratio				1.20	1.20	1.20	1.20	1.20	1.22	1.26	1.31	1.28	1.32	1.34
	Payment to City (PILOT)				15,294,596	15,658,679	16,116,052	16,751,186	17,632,965	18,722,469	19,737,964	21,209,097	22,070,811	23,226,884	24,353,922
	Total Revenue Requirment				321,186,522	328,832,251	338,437,098	351,774,908	370,292,255	393,171,840	414,497,254	445,391,036	463,487,033	487,764,570	511,432,359
	Total Revenue Requirment - $/MWH Sold				55.60	55.69	56.04	57.04	58.79	61.15	62.82	65.77	66.78	68.51	70.03
	Fund Balances														
	O&M Fund				39,501,466	40,765,474	42,301,823	44,414,164	47,378,096	50,882,169	53,798,741	58,292,471	61,511,303	64,963,924	68,570,686
	Principal and Interest Fund				61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724
	Contribution Fund				2,549,099	2,609,780	2,686,009	2,791,864	2,938,827	3,120,411	3,289,661	3,534,849	3,678,469	3,871,147	4,058,987
	Depreciation and Replacement Fund				17,134,026	17,041,428	16,997,394	16,986,156	17,196,946	17,580,813	18,297,033	19,040,681	19,014,541	19,723,142	20,214,694
	Improvement Fund				2,562,679	2,526,913	2,493,644	2,459,626	2,427,430	2,396,240	2,379,686	2,366,588	2,352,895	2,345,214	2,341,300
	Total Fund Balance				123,684,995	124,881,319	126,416,594	128,589,534	131,879,024	135,917,357	139,702,846	145,172,314	148,494,932	152,841,152	157,123,391
	Additional Required Funds					1,196,325	1,535,275	2,172,940	3,289,490	4,038,333	3,785,489	5,469,468	3,322,618	4,346,220	4,282,239
	Depreciation and Replacement Fund - BOY				0	17,134,026	17,041,428	16,997,394	16,986,156	17,196,946	17,580,813	18,297,033	19,040,681	19,014,541	19,723,142
	Capital Additons				0	(7,533,298)	(8,234,179)	(8,286,742)	(8,868,107)	(9,296,580)	(12,530,257)	(13,552,676)	(13,770,336)	(15,348,051)	(16,504,913)
	Addition Funds to meet Minimum				17,134,026	7,440,701	8,190,144	8,275,504	9,078,898	9,680,447	13,246,478	14,296,324	13,744,196	16,056,651	16,996,465
	Depreciation and Replacement Fund - EOY				17,134,026	17,041,428	16,997,394	16,986,156	17,196,946	17,580,813	18,297,033	19,040,681	19,014,541	19,723,142	20,214,694
	Capital Additons					7,533,298	8,234,179	8,286,742	8,868,107	9,296,580	12,530,257	13,552,676	13,770,336	15,348,051	16,504,913
	Additional Funds					(92,597)	(44,035)	(11,238)	210,790	383,866	716,221	743,647	(26,140)	708,601	491,552
	Interest Earned on Fund Balances				5,442,140	5,744,541	5,815,163	5,786,529	5,934,556	6,116,281	6,286,628	6,532,754	6,682,272	6,877,852	7,070,553
	Retail Rates														
	Average Rate	$/MWh			55.60	55.69	56.04	57.04	58.79	61.15	62.82	65.77	66.78	68.51	70.03
	Residential	$/MWh			72.65	72.76	73.23	74.53	76.82	79.90	82.09	85.94	87.26	89.52	91.50
	Commercial	$/MWh			60.14	60.23	60.62	61.70	63.59	66.15	67.95	71.15	72.24	74.11	75.75
	Industrial	$/MWh			39.41	39.47	39.72	40.43	41.67	43.34	44.53	46.62	47.34	48.56	49.64
	Public Street & Highway Lighting	$/MWh			105.38	105.54	106.22	108.10	111.43	115.90	119.07	124.66	126.57	129.85	132.72
	COMPARISON														
	Residential Rates	$/MWh													
	KG&E Residential Rates				89.74	88.68	88.62	89.08	89.63	90.75	92.18	93.96	95.41	97.61	100.06
	Wichita Residential Rates				72.65	72.76	73.23	74.53	76.82	79.90	82.09	85.94	87.26	89.52	91.50
	Difference				17.09	15.92	15.39	14.55	12.81	10.85	10.09	8.02	8.14	8.09	8.55
	MWh Sales				1,544,921	1,578,538	1,613,616	1,650,156	1,685,235	1,721,045	1,756,854	1,802,895	1,850,397	1,896,438	1,945,388
	$ Difference b/w Rates				26,401,434	25,125,584	24,834,593	24,012,793	21,593,084	18,672,815	17,727,534	14,458,022	15,068,678	15,334,109	16,640,625
	Commercial Rates	$/MWh													
	KG&E Commercial Rates				74.29	73.41	73.36	73.74	74.20	75.13	76.31	77.78	78.98	80.80	82.83
	Wichita Commercial Rates				60.14	60.23	60.62	61.70	63.59	66.15	67.95	71.15	72.24	74.11	75.75
	Difference				14.15	13.18	12.74	12.05	10.61	8.98	8.35	6.64	6.74	6.69	7.08
	MWh Sales				1,746,111	1,784,913	1,825,333	1,864,135	1,903,746	1,943,357	1,994,285	2,046,830	2,097,758	2,151,905	2,207,450
	$ Difference b/w Rates				24,702,130	23,519,041	23,256,269	22,456,195	20,193,166	17,454,663	16,658,701	13,588,189	14,141,873	14,404,043	15,631,314
	Industrial Rates	$/MWh													
	KG&E Industrial Rates				48.68	48.10	48.07	48.32	48.62	49.23	50.00	50.97	51.75	52.95	54.28
	Wichita Industrial Rates				39.41	39.47	39.72	40.43	41.67	43.34	44.53	46.62	47.34	48.56	49.64
	Difference				9.27	8.63	8.35	7.89	6.95	5.89	5.47	4.35	4.42	4.39	4.64
	MWh Sales				2,422,915	2,476,758	2,532,844	2,586,687	2,641,651	2,696,615	2,767,284	2,840,195	2,910,864	2,985,999	3,063,073
	$ Difference b/w Rates				22,460,611	21,384,878	21,145,950	20,418,477	18,360,799	15,870,793	15,147,058	12,355,170	12,858,612	13,096,992	14,212,898
	Public Street & Highway Lighting Rates	$/MWh													
	KG&E Public Street & Highway Lighting Rates				130.16	128.63	128.54	129.21	130.01	131.64	133.70	136.29	138.38	141.58	145.13
	Wichita Public Street & Highway Lighting Rates				105.38	105.54	106.22	108.10	111.43	115.90	119.07	124.66	126.57	129.85	132.72
	Difference				24.79	23.09	22.32	21.11	18.59	15.74	14.64	11.63	11.81	11.73	12.41

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	Historical	Historical / Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
MWh Sales			29,124	29,771	30,445	31,093	31,753	32,414	33,263	34,140	34,989	35,892	36,819
$ Difference b/w Rates			721,909	687,334	679,655	656,273	590,137	510,105	486,844	397,109	413,290	420,952	456,819
Average Rates / Total Sales		$/MWh											
KG&E Average Rates / Total Sales			68.68	67.87	67.82	68.18	68.60	69.46	70.55	71.91	73.02	74.70	76.58
Wichita Average Rates / Total Sales			55.60	55.69	56.04	57.04	58.79	61.15	62.82	65.77	66.78	68.51	70.03
Difference			13.08	12.18	11.78	11.14	9.81	8.30	7.72	6.14	6.23	6.19	6.55
MWh Sales			5,776,688	5,905,059	6,038,779	6,167,149	6,298,195	6,429,240	6,597,727	6,771,562	6,940,049	7,119,185	7,302,944
$ Difference b/w Rates			75,552,544	71,934,014	71,130,314	68,683,254	61,761,679	53,385,850	50,951,364	41,560,068	43,253,536	44,055,394	47,809,055
NPV of Difference				KGE-WMU	WMU-KGE								
Rate 8.5%			$674,128,174	$674,128,174	($674,128,174)								
NPV Revenu Stream KGE			$396,739,066	$400,766,265	$409,567,412	$420,458,162	$432,053,934	$446,557,690	$465,448,618	$486,951,104	$506,740,569	$531,819,964	$559,241,414
NPV Value - KGE Revenue Stream			$5,076,282,001										
				($71,934,014)									
NPV Revenu Stream KGE			$321,186,522	$328,832,251	$338,437,098	$351,774,908	$370,292,255	$393,171,840	$414,497,254	$445,391,036	$463,487,033	$487,764,570	$511,432,359
NPV Value - WMU Revenue Stream			$4,402,153,827										
Annual Difference			($75,552,544)	($71,934,014)	($71,130,314)	($68,683,254)	($61,761,679)	($53,385,850)	($50,951,364)	($41,560,068)	($43,253,536)	($44,055,394)	($47,809,055)

Projected Operating Results
Wichita Municipal System

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
Number of Customers											
Residential	198,424	203,546	208,800	214,189	219,718	225,389	231,207	237,175	243,297	249,577	256,019
Commercial	21,079	21,623	22,182	22,754	23,341	23,944	24,562	25,196	25,846	26,513	27,198
Industrial	1,225	1,257	1,289	1,323	1,357	1,392	1,428	1,465	1,502	1,541	1,581
Public Street & Highway Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Retail	220,729	226,426	232,271	238,266	244,416	250,725	257,197	263,835	270,645	277,631	284,797
Percent Growth	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%
Load											
Usage per Customer											
Usage Per Customer (MWH/Customer)											
Residential Sales	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Commercial Sales	107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4	107.4
Industrial Sales	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3	2,564.3
Public Street & Highway Lighting	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
MWH Sales											
Residential Sales	2,047,113	2,099,952	2,154,156	2,209,759	2,266,797	2,325,307	2,385,328	2,446,898	2,510,057	2,574,846	2,641,307
Commercial Sales	2,264,428	2,322,878	2,382,835	2,444,341	2,507,434	2,572,155	2,638,548	2,706,653	2,776,517	2,848,184	2,921,701
Industrial Sales	3,142,136	3,223,241	3,306,439	3,391,784	3,479,332	3,569,141	3,661,267	3,755,771	3,852,714	3,952,160	4,054,173
Public Street & Highway Lighting	37,769	38,744	39,744	40,770	41,822	42,902	44,009	45,145	46,311	47,506	48,732
Total Retail Sales	7,491,447	7,684,815	7,883,175	8,086,654	8,295,386	8,509,505	8,729,152	8,954,467	9,185,599	9,422,696	9,665,914
% Growth	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%
System Loss Factor	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
System Losses	391,039	401,133	411,487	422,108	433,004	444,180	455,645	467,406	479,471	491,847	504,543
NEFL	7,882,486	8,085,948	8,294,661	8,508,762	8,728,389	8,953,685	9,184,797	9,421,874	9,665,070	9,914,544	10,170,457
Purchased Power											
NEFL	7,882,486	8,085,948	8,294,661	8,508,762	8,728,389	8,953,685	9,184,797	9,421,874	9,665,070	9,914,544	10,170,457
All In Energy Price - $/MWH	50.36	52.09	53.39	54.62	55.76	56.81	57.76	58.61	59.36	60.11	60.88
Purchased Power Cost - Including Trans Wheeling	397,001,175	421,184,435	442,857,395	464,714,294	486,672,670	508,645,177	530,540,071	552,261,762	573,711,436	595,994,209	619,142,438
Less Transmission Wheeling	23,686,161	24,904,984	26,186,524	27,534,008	28,950,830	30,440,558	32,006,943	33,653,930	35,385,666	37,206,513	39,121,055
Purchased Power Cost - w/o Trans Wheeling	373,315,014	396,279,451	416,670,872	437,180,286	457,721,839	478,204,619	498,533,128	518,607,832	538,325,770	558,787,697	580,021,384
Plant in Service											
EOY Balances											
Other Plant - Premium	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533
Distribution Plant	465,159,697	483,782,688	503,809,391	525,345,610	548,505,124	573,410,292	600,192,691	628,993,817	659,965,834	693,272,371	729,089,395
General Plant	11,585,007	12,048,821	12,547,595	13,083,964	13,660,761	14,281,036	14,948,063	15,665,368	16,436,739	17,266,253	18,158,292
Total Electric Plant	476,744,704	495,831,509	516,356,985	538,429,573	562,165,886	587,691,327	615,140,754	644,659,185	676,402,573	710,538,625	747,247,687
Accumulated Depreciation (EOY)											
Other Plant	72,787,013	78,852,598	84,918,182	90,983,766	97,049,351	103,114,935	109,180,520	115,246,104	121,311,689	127,377,273	133,442,858
Distribution Plant	114,200,616	125,969,176	138,224,909	151,004,534	164,347,541	178,296,394	192,896,759	208,197,744	224,252,159	241,116,793	258,852,716
General Plant	3,437,277	3,791,495	4,160,375	4,545,024	4,946,629	5,366,470	5,805,920	6,266,458	6,749,674	7,257,275	7,791,102
Total Electric Plant	190,424,906	208,613,268	227,303,465	246,533,324	266,343,521	286,777,799	307,883,199	329,710,307	352,313,521	375,751,341	400,086,675
Net Plant In Service (EOY)											
Other Plant	109,180,520	103,114,935	97,049,351	90,983,766	84,918,182	78,852,598	72,787,013	66,721,429	60,655,844	54,590,260	48,524,675
Distribution Plant	350,959,081	357,813,512	365,584,482	374,341,075	384,157,584	395,113,898	407,295,931	420,796,073	435,713,675	452,155,579	470,236,679
General Plant	8,147,729	8,257,326	8,387,220	8,538,940	8,714,132	8,914,566	9,142,143	9,398,909	9,687,066	10,008,978	10,367,190
Total Electric Plant	468,287,331	469,185,774	471,021,053	473,863,782	477,789,898	482,881,061	489,225,087	496,916,411	506,056,585	516,754,817	529,128,545
Average Balance											
Other Plant	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533	181,967,533
Distribution Plant	456,500,862	474,471,193	493,796,040	514,577,500	536,925,367	560,957,708	586,801,491	614,593,254	644,479,825	676,619,102	711,180,883
General Plant	11,369,355	11,816,914	12,298,208	12,815,779	13,372,362	13,970,899	14,614,549	15,306,715	16,051,054	16,851,496	17,712,273
Total Electric Plant	649,837,750	668,255,639	688,061,780	709,360,812	732,265,262	756,896,140	783,383,573	811,867,502	842,498,412	875,438,132	910,860,689
Yearly Net Additions (Renewals & Replacements)											
Other	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant	17,317,669	18,622,991	20,026,703	21,536,219	23,159,515	24,905,167	26,782,399	28,801,127	30,972,017	33,306,538	35,817,024
General Plant	431,304	463,814	498,774	536,369	576,798	620,274	667,027	717,305	771,372	829,514	892,039
Total Electric Plant	17,748,973	19,086,805	20,525,476	22,072,588	23,736,313	25,525,442	27,449,426	29,518,431	31,743,388	34,136,052	36,709,062
Depreciation ($)											
Other Plant	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584	6,065,584
Distribution Plant	11,315,535	11,768,560	12,255,733	12,779,625	13,343,007	13,948,853	14,600,365	15,300,985	16,054,414	16,864,634	17,735,923
General Plant	340,582	354,217	368,880	384,649	401,606	419,841	439,450	460,538	483,215	507,602	533,826
Total Electric Plant	17,721,701	18,188,362	18,690,197	19,229,859	19,810,197	20,434,278	21,105,400	21,827,108	22,603,214	23,437,820	24,335,334

Revenue Requirement

	2011 Projected	2012 Projected	2013 Projected	2014 Projected	2015 Projected	2016 Projected	2017 Projected	2018 Projected	2019 Projected	2020 Projected	2021 Projected
Operations & Maintenance Expense											
Purchased Power	373,315,014	396,279,451	416,670,872	437,180,286	457,721,839	478,204,619	498,533,128	518,607,832	538,325,770	558,787,697	580,021,384
Purchased Power - $/MWH Sold	49.83	51.57	52.86	54.06	55.18	56.20	57.11	57.92	58.61	59.30	60.01
Transmission	23,686,161	24,904,984	26,186,524	27,534,008	28,950,830	30,440,558	32,006,943	33,653,930	35,385,666	37,206,513	39,121,055
Distribution	18,050,189	18,772,841	19,549,963	20,385,661	21,284,349	22,250,776	23,290,048	24,407,655	25,609,502	26,901,939	28,291,793
General	18,050,189	18,772,841	19,549,963	20,385,661	21,284,349	22,250,776	23,290,048	24,407,655	25,609,502	26,901,939	28,291,793
Total O&M	433,101,554	458,730,117	481,957,322	505,485,616	529,241,368	553,146,730	577,120,167	601,077,073	624,930,441	649,798,086	675,726,023
Debt Service	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724
Debt Service Coverage Ratio	1.36	1.39	1.41	1.43	1.46	1.49	1.52	1.56	1.59	1.64	1.68
Additional Funding of Reserves	4,341,625	5,228,397	4,577,806	4,819,517	4,873,080	4,950,744	5,010,183	5,059,388	5,096,605	5,383,801	5,637,341
Less Interest Earnings	(7,265,926)	(7,501,204)	(7,707,205)	(7,924,083)	(8,143,372)	(8,366,155)	(8,591,613)	(8,819,286)	(9,048,633)	(9,290,904)	(9,544,585)
Capital Paid From Current Earnings	17,748,973	19,086,805	20,525,476	22,072,588	23,736,313	25,525,442	27,449,426	29,518,431	31,743,388	34,136,052	36,709,062
Sub-Total Revenue Requirment	509,863,950	537,481,841	561,291,123	586,391,362	611,645,113	637,194,484	662,925,888	688,773,330	714,659,525	741,964,759	770,465,567
Additional Requriements to Meet Debt Service Coverage Minimun	-	-	-	-	-	-	-	-	-	-	-
Sub-Total Revenue Requirment	509,863,950	537,481,841	561,291,123	586,391,362	611,645,113	637,194,484	662,925,888	688,773,330	714,659,525	741,964,759	770,465,567
Debt Service Coverage Ratio	1.36	1.39	1.41	1.43	1.46	1.49	1.52	1.56	1.59	1.64	1.68
Payment to City (PILOT)	25,493,198	26,874,092	28,064,556	29,319,568	30,582,256	31,859,724	33,146,294	34,438,667	35,732,976	37,098,238	38,523,278
Total Revenue Requirment	535,357,148	564,355,933	589,355,679	615,710,930	642,227,369	669,054,208	696,072,182	723,211,997	750,392,501	779,062,997	808,988,845
Total Revenue Requirment - $/MWH Sold	71.46	73.44	74.76	76.14	77.42	78.62	79.74	80.77	81.69	82.68	83.70
Fund Balances											
O&M Fund	72,183,592	76,455,020	80,326,220	84,247,603	88,206,895	92,191,122	96,186,695	100,179,512	104,155,073	108,299,681	112,621,004
Principal and Interest Fund	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724	61,937,724
Contribution Fund	4,248,866	4,479,015	4,677,426	4,886,595	5,097,043	5,309,954	5,524,382	5,739,778	5,955,496	6,183,040	6,420,546
Depreciation and Replacement Fund	20,753,396	21,475,725	21,974,743	22,649,495	23,333,205	24,061,355	24,829,817	25,642,535	26,502,160	27,460,318	28,476,961
Improvement Fund	2,341,437	2,345,929	2,355,105	2,369,319	2,388,949	2,414,405	2,446,125	2,484,582	2,530,283	2,583,774	2,645,643
Total Fund Balance	161,465,015	166,693,413	171,271,219	176,090,736	180,963,816	185,914,560	190,924,743	195,984,131	201,080,737	206,464,537	212,101,878
Additional Required Funds	4,341,625	5,228,397	4,577,806	4,819,517	4,873,080	4,950,744	5,010,183	5,059,388	5,096,605	5,383,801	5,637,341
Depreciation and Replacement Fund - BOY	20,214,694	20,753,396	21,475,725	21,974,743	22,649,495	23,333,205	24,061,355	24,829,817	25,642,535	26,502,160	27,460,318
Capital Additons	(17,748,973)	(19,086,805)	(20,525,476)	(22,072,588)	(23,736,313)	(25,525,442)	(27,449,426)	(29,518,431)	(31,743,388)	(34,136,052)	(36,709,062)
Addition Funds to meet Minimum	18,287,675	19,809,134	21,024,494	22,747,340	24,420,022	26,253,591	28,217,888	30,331,150	32,603,013	35,094,210	37,725,705
Depreciation and Replacement Fund - EOY	20,753,396	21,475,725	21,974,743	22,649,495	23,333,205	24,061,355	24,829,817	25,642,535	26,502,160	27,460,318	28,476,961
Capital Additons	17,748,973	19,086,805	20,525,476	22,072,588	23,736,313	25,525,442	27,449,426	29,518,431	31,743,388	34,136,052	36,709,062
Additional Funds	538,702	722,329	499,018	674,753	683,710	728,150	768,462	812,719	859,625	958,158	1,016,643
Interest Earned on Fund Balances	7,265,926	7,501,204	7,707,205	7,924,083	8,143,372	8,366,155	8,591,613	8,819,286	9,048,633	9,290,904	9,544,585
Retail Rates											
Average Rate	71.46	73.44	74.76	76.14	77.42	78.62	79.74	80.77	81.69	82.68	83.70
Residential	93.37	95.96	97.68	99.49	101.16	102.73	104.19	105.53	106.74	108.03	109.36
Commercial	77.30	79.44	80.87	82.36	83.74	85.05	86.25	87.36	88.36	89.43	90.53
Industrial	50.65	52.05	52.99	53.97	54.87	55.73	56.52	57.25	57.90	58.60	59.32
Public Street & Highway Lighting	135.44	139.18	141.69	144.30	146.73	149.01	151.13	153.07	154.83	156.70	158.62

COMPARISON

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Residential Rates											
KG&E Residential Rates	102.28	105.25	108.12	111.22	114.71	118.52	122.43	126.40	130.44	134.63	138.97
Wichita Residential Rates	93.37	95.96	97.68	99.49	101.16	102.73	104.19	105.53	106.74	108.03	109.36
Difference	8.91	9.30	10.44	11.74	13.55	15.79	18.24	20.87	23.70	26.59	29.61
MWh Sales	1,995,602	2,047,113	2,099,952	2,154,156	2,209,759	2,266,797	2,325,307	2,385,328	2,446,898	2,510,057	2,574,846
$ Difference b/w Rates	17,774,343	19,030,359	21,922,888	25,279,717	29,945,293	35,795,921	42,402,181	49,792,425	57,998,447	66,752,906	76,251,650
Commercial Rates											
KG&E Commercial Rates	84.67	87.13	89.51	92.07	94.96	98.12	101.35	104.64	107.99	111.45	115.05
Wichita Commercial Rates	77.30	79.44	80.87	82.36	83.74	85.05	86.25	87.36	88.36	89.43	90.53
Difference	7.37	7.70	8.64	9.71	11.22	13.07	15.10	17.28	19.62	22.02	24.52
MWh Sales	2,264,428	2,322,878	2,382,835	2,444,341	2,507,434	2,572,155	2,638,548	2,706,653	2,776,517	2,848,184	2,921,701
$ Difference b/w Rates	16,696,268	17,876,102	20,593,189	23,746,415	28,129,008	33,624,775	39,830,342	46,772,343	54,480,642	62,704,113	71,626,725
Industrial Rates											
KG&E Industrial Rates	55.48	57.09	58.65	60.33	62.22	64.29	66.41	68.57	70.76	73.03	75.39
Wichita Industrial Rates	50.65	52.05	52.99	53.97	54.87	55.73	56.52	57.25	57.90	58.60	59.32
Difference	4.83	5.04	5.66	6.37	7.35	8.57	9.89	11.32	12.86	14.43	16.06
MWh Sales	3,142,136	3,223,241	3,306,439	3,391,784	3,479,332	3,569,141	3,661,267	3,755,771	3,852,714	3,952,160	4,054,173
$ Difference b/w Rates	15,181,216	16,253,990	18,724,523	21,591,620	25,576,527	30,573,598	36,216,060	42,528,130	49,536,963	57,014,221	65,127,178
Public Street & Highway Lighting Rates											
KG&E Public Street & Highway Lighting Rates	148.36	152.66	156.83	161.32	166.38	171.92	177.58	183.35	189.21	195.27	201.58
Wichita Public Street & Highway Lighting Rates	135.44	139.18	141.69	144.30	146.73	149.01	151.13	153.07	154.83	156.70	158.62
Difference	12.92	13.48	15.14	17.02	19.66	22.90	26.45	30.28	34.38	38.57	42.95

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
MWh Sales	37,769	38,744	39,744	40,770	41,822	42,902	44,009	45,145	46,311	47,506	48,732
$ Difference b/w Rates	487,941	522,422	601,827	693,979	822,058	982,670	1,164,025	1,366,902	1,592,174	1,832,501	2,093,261
Average Rates / Total Sales											
KG&E Average Rates / Total	78.28	80.55	82.75	85.12	87.79	90.71	93.70	96.74	99.83	103.03	106.36
Wichita Average Rates / Total	71.46	73.44	74.76	76.14	77.42	78.62	79.74	80.77	81.69	82.68	83.70
Difference	6.82	7.11	7.99	8.98	10.37	12.09	13.96	15.98	18.14	20.35	22.66
MWh Sales	7,491,447	7,684,815	7,883,175	8,086,654	8,295,386	8,509,505	8,729,152	8,954,467	9,185,599	9,422,696	9,665,914
$ Difference b/w Rates	51,066,264	54,674,839	62,985,168	72,629,448	86,033,799	102,842,843	121,822,842	143,055,253	166,631,423	191,783,268	219,073,467
NPV of Difference											
Rate 8.5%											
NPV Revenu Stream KGE	$586,423,412	$619,030,771	$652,340,847	$688,340,377	$728,261,168	$771,897,051	$817,895,024	$866,267,250	$917,023,924	$970,846,265	$1,028,062,312
NPV Value - KGE Revenue Stream											
NPV Revenu Stream KGE	$535,357,148	$564,355,933	$589,355,679	$615,710,930	$642,227,369	$669,054,208	$696,072,182	$723,211,997	$750,392,501	$779,062,997	$808,988,845
NPV Value - WMU Revenue Stream											
Annual Difference	($51,066,264)	($54,674,839)	($62,985,168)	($72,629,448)	($86,033,799)	($102,842,843)	($121,822,842)	($143,055,253)	($166,631,423)	($191,783,268)	($219,073,467)

Projected Operating Results
Kansas Gas and Electric (KGE a WRI Company)

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
	Historical	Historical	Historical	Historical	Historical	Historical	Historical	Historical	Historical / Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
Market Prices																	
All In Energy Price - $/MWH								32.87	33.46	34.05	34.64	35.43	36.76	38.58	40.79	42.14	44.70
Percent Change								N/A	2%	2%	2%	2%	4%	5%	6%	3%	6%
Energy Only Price - $/MWH											$26.12	$27.71	$28.23	$29.13	$30.47	$32.18	$33.20
Percent Change											N/A	6.07%	1.89%	3.19%	4.60%	5.62%	3.15%
Capacity - $/KW-yr											$74.61	$67.65	$74.71	$82.74	$90.43	$87.19	$100.73
$/Kwh											$8.52	$7.72	$8.53	$9.44	$10.32	$9.95	$11.50
System Capacity Requirements																	
System Peak (MW)	1,752	1,678	1,811	1,747	1,855	2,034	2,476	2,205	2,114	2,160	2,208	2,258	2,306	2,355	2,404	2,467	2,532
System Peak (MW) - EIA Form 411 10 Yr																	
Total System Capacity (MW)									2270	2300	2530	2530	2530	2530	2530	2530	2530
Existing Capacity	2,530	2,530	2,530	2,530	2,530	2,533	2,534	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539
Capacity Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity Additions - Cumulative Total	0	0	0	0	0	0	0	0	0	0	0	0	44	99	154	224	297
Total Capacity	2,530	2,530	2,530	2,530	2,530	2,533	2,534	2,539	2,539	2,539	2,539	2,539	2,583	2,638	2,692	2,763	2,836
Reserve Capacity Calculation (MW)																	
RM Calculation for Additional Capacity																	
System Peak (MW)									2,114	2,160	2,208	2,258	2,306	2,355	2,404	2,467	2,532
Reserve Margin									254	259	265	271	277	283	288	296	304
Total requirements									2,368	2,419	2,473	2,529	2,583	2,638	2,692	2,763	2,836
Surplus Capacity									425	379	331	281	233	184	135	72	7
Required Reserves									254	259	265	271	277	283	288	296	304
Required Reserves form Surplus									254	259	265	271	233	184	135	72	7
Required Reserves form Market									-	-	-	-	44	99	154	224	297
Reserve Margin	44.4%	50.8%	39.7%	44.8%	36.4%	24.5%	2.3%	15.1%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
System Energy Requirements																	
MWH Sales - Retail																	
Residential Sales	2,340,534	2,101,531	2,385,811	2,384,049	2,384,609	2,502,825	2,489,796	2,783,998	2,566,926	2,622,782	2,681,066	2,741,778	2,800,062	2,859,561	2,919,059	2,995,557	3,074,483
% of Total Retail	31.3%	28.8%	30.8%	30.3%	29.6%	30.4%	30.1%	31.7%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%
Commercial Sales	1,907,682	1,892,382	1,990,616	2,067,989	2,094,819	2,186,336	2,211,016	2,383,197	2,194,091	2,241,833	2,291,652	2,343,546	2,393,365	2,444,221	2,495,077	2,560,464	2,627,927
% of Total Retail	25.5%	26.0%	25.7%	26.3%	26.0%	26.5%	26.8%	27.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%
Industrial Sales	3,194,385	3,247,966	3,323,450	3,370,970	3,541,863	3,500,982	3,517,539	3,568,948	3,608,174	3,686,687	3,768,614	3,853,954	3,935,880	4,019,513	4,103,146	4,210,675	4,321,617
% of Total Retail	42.7%	44.6%	42.9%	42.8%	43.9%	42.5%	42.6%	40.6%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%
Public Street & Highway Lighting	45,896	45,399	45,092	44,860	45,352	45,094	45,323	45,485	50,021	51,109	52,245	53,428	54,564	55,723	56,882	58,373	59,911
% of Total Retail	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Other	-	-	-	-	-	-	-	-									
Total Retail	7,488,497	7,287,278	7,744,969	7,867,868	8,066,643	8,235,237	8,263,674	8,781,628	8,419,212	8,602,411	8,793,576	8,992,706	9,183,870	9,379,018	9,574,165	9,825,069	10,083,937
% Change Per Year	3%	-3%	6%	2%	3%	2%	0.35%	6%	-4.1%	2.18%	2.2%	2.3%	2.1%	2.1%	2.1%	2.6%	2.6%

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Distribution Losses									5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
Retail NEFL									8,858,679	9,051,441	9,252,584	9,462,108	9,663,251	9,868,585	10,073,918	10,337,919	10,610,300
Net Generation (Projected Per Prosym)																	
Generating Stations	8,826,556	8,926,006	10,692,321	11,257,502	11,484,335	11,511,913	10,668,613	12,439,354	12,633,332	12,827,309	12,827,309	12,867,093	12,898,360	12,902,264	12,799,693	12,891,908	12,774,534
Purchased Power	430,053	545,230	(263,320)	(1,029,350)	259,419	512,263	877,039	792,114	0	0	0	0	0	0	0	0	0
Exchanges - Net	-	(447,912)	-	-	(1,598,545)	(210,114)	(323,716)	(2,045,019)	(941,309)	(941,612)	(891,452)	(849,123)	(806,760)	(756,528)	(679,744)	(636,904)	(539,709)
Wheeling - Net	-	-	-	-	-	-	64,796	39,160									
Total Sources	9,256,609	9,023,324	10,429,001	10,228,152	10,145,209	11,814,062	11,286,732	11,225,609	11,692,023	11,885,697	11,935,858	12,017,971	12,091,601	12,145,737	12,119,950	12,255,004	12,234,825
MWH Sales - Wholesale	1,168,178	1,249,113	2,004,107	1,589,974	1,292,203	2,705,930	2,100,888	1,540,546	2,833,344	2,834,256	2,683,274	2,555,863	2,428,350	2,277,152	2,046,031	1,917,085	1,624,525
					0.55	0.07	0.13	0.57 .									
					0.33												
Annual System Load Factor - Sales	41.8%	40.7%	47.1%	46.2%	45.8%	53.2%	50.9%	50.5%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%
Historical Losses %	6.48%	5.40%	6.52%	7.53%	7.75%	7.39%	8.17%	8.05%									
Number of Customers																	
Residential	229,043	238,286	241,046	243,922	245,994	247,630	250,647	252,735	257,426	263,027	268,872	274,961	280,806	286,773	292,739	300,411	308,326
Commercial	22,732	22,840	23,117	23,795	24,706	25,337	25,776	27,063	25,688	26,247	26,831	27,438	28,021	28,617	29,212	29,978	30,768
Industrial	4,373	4,149	4,007	3,899	3,802	3,712	3,605	3,521	3,548	3,626	3,706	3,790	3,871	3,953	4,035	4,141	4,250
Public Street & Highway Lighting	847	-	-	-	-	-	-	-									
Total Retail	256,995	265,275	268,170	271,616	274,502	276,679	280,028	283,319	286,662	292,900	299,409	306,189	312,698	319,342	325,987	334,530	343,344
% Change Per Year	0.7%	3.2%	1.1%	1.3%	1.1%	0.8%	1.2%	1.2%	1.2%	2.2%	2.2%	2.3%	2.1%	2.1%	2.1%	2.6%	2.6%
Usage Per Customer (MWH/Customer)																	
Residential Sales	10.2	8.8	9.9	9.8	9.7	10.1	9.9	11.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Commercial Sales	83.9	82.9	86.1	86.9	84.8	86.3	85.8	88.1	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4
Industrial Sales	730.5	782.8	829.4	864.6	931.6	943.2	975.7	1013.6	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9
Public Street & Highway Lighting	54.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Retail	29.1	27.5	28.9	29.0	29.4	29.8	29.5	31.0	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4
Retail Rate - Historical																	
Average Rate																	
Residential Sales	93.96	92.38	91.82	92.31	92.94	90.48	86.24	85.33	84.8								
Commercial Sales	81.69	81.38	81.81	81	81.94	80.94	73.68	71.53	70.2								
Industrial Sales	54.14	53.64	53.94	53.73	51.65	50.11	47.08	46.89	46.0								
Public Street & Highway Lighting	129.68	128.53	135.7	136.65	138.21	137.78	125.96	123.01	123.0								
Total Retail	74.07	72.48	73.25	73.06	72.21	71.04	66.43	66.16	64.9								
	-1%	-2%	1%	0%	-1%	-2%	-6%	0%									
Plant in Service																	
EOY Gross Plant in Service																	
Production Plant																	
Steam Plant	463,197,563	469,257,863	493,196,163	495,820,289	507,432,558	516,107,587	529,926,692	537,822,283	574,153,867	588,635,925	603,512,268	618,764,574	634,387,103	650,404,069	666,825,430	683,661,397	700,922,437
Nuclear Plant	1,358,428,443	1,355,676,884	1,366,387,300	1,376,894,092	1,371,878,429	1,381,999,946	1,380,659,973	1,377,347,737	1,378,237,869	1,380,293,835	1,382,356,890	1,384,423,029	1,386,490,239	1,388,560,535	1,390,633,923	1,392,710,407	1,394,789,992
Hydro Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Plant	0	0	0	0	0	0	0	0	342,449	412,583	497,244	599,279	722,131	870,168	1,048,553	1,263,506	1,522,525
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New -CC									0	0	0	0	0	0	0	0	0
Total Production Plant	1,821,626,006	1,824,934,747	1,859,583,463	1,872,714,381	1,879,310,987	1,898,107,533	1,910,586,665	1,915,170,020	1,952,734,185	1,969,342,343	1,986,366,403	2,003,786,881	2,021,599,473	2,039,834,772	2,058,507,906	2,077,635,310	2,097,234,953
Transmission Plant	213,927,733	215,897,994	217,178,878	219,495,370	226,811,681	242,244,504	257,025,787	260,848,850	259,127,696	266,227,992	273,149,919	280,251,817	292,241,351	305,912,442	320,084,437	336,684,489	354,194,266
Distribution Plant	357,486,160	371,713,485	389,472,550	408,861,069	435,480,249	452,540,075	478,904,541	496,402,077	516,870,444	542,443,899	581,843,933	624,363,839	668,444,556	715,631,226	765,817,201	823,857,474	886,418,723
General Plant	62,249,877	62,062,980	65,223,284	62,009,427	60,738,135	67,958,023	70,429,832	73,518,094	71,985,508	70,954,828	72,572,784	74,285,149	76,172,232	78,192,393	80,313,137	82,708,112	85,253,856
Total Electric Plant	2,455,289,776	2,474,609,206	2,531,458,175	2,563,080,247	2,602,341,052	2,660,850,135	2,716,946,825	2,745,939,041	2,800,717,833	2,848,969,062	2,913,933,040	2,982,687,687	3,058,457,612	3,139,570,833	3,224,722,681	3,320,885,385	3,423,101,799
Accumulated Depreciation (EOY)																	
Production Plant																	
Steam Plant	237,273,047	251,335,981	264,638,505	273,821,046	284,731,023	294,198,924	305,853,160	316,467,953	328,391,204	344,441,806	360,897,657	377,769,389	395,067,304	412,801,955	430,984,369	449,625,852	468,737,994

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Nuclear Plant	225,168,340	256,473,284	295,027,887	327,497,361	361,014,787	402,228,514	443,061,527	482,032,308	460,885,272	496,829,359	532,827,118	568,878,681	604,984,102	641,143,436	677,356,762	713,624,162	749,945,716
Hydro Plant	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
Other Plant	0	0	0	0	0	0	0	0	4,315	14,351	26,221	40,308	57,068	77,055	100,936	129,513	163,755
New - CT	0	0	0	0	0	0	0	0	0								
New - CC	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
Total Production Plant	462,441,387	507,809,265	559,666,392	601,318,407	645,745,810	696,427,438	748,914,687	798,500,261	789,280,791	841,285,516	893,750,996	946,688,378	1,000,108,474	1,054,022,445	1,108,442,067	1,163,379,527	1,218,847,465
Transmission Plant	69,505,933	74,490,707	79,866,420	81,527,592	87,546,449	95,129,958	99,185,552	102,858,104	105,308,127	112,819,511	120,531,381	128,443,759	136,629,101	145,181,331	154,131,653	163,521,946	173,399,931
Distribution Plant	111,972,584	121,066,587	129,963,118	139,277,988	148,457,919	155,977,243	166,478,504	174,516,508	188,367,819	201,252,328	214,927,114	229,598,297	245,322,810	262,157,413	280,176,366	299,511,683	320,313,883
General Plant	24,596,807	28,478,686	32,711,316	26,488,657	28,859,979	30,796,700	29,163,328	29,986,709	29,799,153	31,900,268	34,010,015	36,168,715	38,380,325	40,649,368	42,979,279	45,375,568	47,844,481
Total Electric Plant	668,516,711	731,845,245	802,207,246	848,612,644	910,610,157	978,331,339	1,043,742,071	1,105,861,582	1,112,755,890	1,187,257,622	1,263,219,505	1,340,899,149	1,420,440,709	1,502,010,557	1,585,729,366	1,671,788,723	1,760,405,760
Net Plant In Service (EOY)																	
Production Plant																	
Steam Plant	225,924,516	217,921,882	228,557,658	221,999,243	222,701,535	221,908,663	224,073,532	221,354,330	245,762,663	244,194,120	242,614,611	240,995,184	239,319,799	237,602,114	235,841,061	234,035,545	232,184,443
Nuclear Plant	1,133,260,103	1,099,203,600	1,071,359,413	1,049,396,731	1,010,863,642	979,771,432	937,598,446	895,315,429	917,352,597	883,464,476	849,529,772	815,544,348	781,506,136	747,417,099	713,277,161	679,086,245	644,844,276
Hydro Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Plant	0	0	0	0	0	0	0	0	338,134	398,232	471,024	558,972	665,064	793,113	947,617	1,133,993	1,358,769
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New - CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	1,359,184,619	1,317,125,482	1,299,917,071	1,271,395,974	1,233,565,177	1,201,680,095	1,161,671,978	1,116,669,759	1,163,453,394	1,128,056,828	1,092,615,407	1,057,098,503	1,021,490,999	985,812,327	950,065,839	914,255,783	878,387,489
Transmission Plant	144,421,800	141,407,287	137,312,458	137,967,778	139,265,232	147,114,546	157,840,235	157,990,746	153,819,569	153,408,481	152,618,539	151,808,059	155,612,250	160,731,111	165,952,783	173,162,543	180,794,336
Distribution Plant	245,513,576	250,646,898	259,509,432	269,583,081	287,022,330	296,562,832	312,426,037	321,885,569	328,502,625	341,191,571	366,916,820	394,765,542	423,121,747	453,473,812	485,640,835	524,345,791	566,104,840
General Plant	37,653,070	33,584,294	32,511,968	35,520,770	31,878,156	37,161,323	41,266,504	43,531,385	42,186,355	39,054,560	38,562,770	38,116,434	37,791,908	37,543,025	37,333,858	37,332,544	37,409,375
Total Electric Plant	1,786,773,065	1,742,763,961	1,729,250,929	1,714,467,603	1,691,730,895	1,682,518,796	1,673,204,754	1,640,077,459	1,687,961,943	1,661,711,440	1,650,713,535	1,641,788,538	1,638,016,904	1,637,560,275	1,638,993,315	1,649,096,661	1,662,696,039
Average Balance - Gross Plant in Service																	
Production Plant																	
Steam Plant	456,975,194	466,227,713	481,227,013	494,508,226	501,626,424	511,770,073	523,017,140	533,874,488	555,988,075	581,394,896	596,074,097	611,138,421	626,575,838	642,395,586	658,614,749	675,243,414	692,291,917
Nuclear Plant	1,360,870,207	1,357,052,664	1,361,032,092	1,371,640,696	1,374,386,261	1,376,939,188	1,381,329,960	1,379,003,855	1,377,792,803	1,379,265,852	1,381,325,363	1,383,389,960	1,385,456,634	1,387,525,387	1,389,597,229	1,391,672,165	1,393,750,199
Hydro Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Plant	0	0	0	0	0	0	0	0	171,225	377,516	454,914	548,262	660,705	796,150	959,360	1,156,029	1,393,015
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New - CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	1,817,845,400	1,823,280,377	1,842,259,105	1,866,148,922	1,876,012,684	1,888,709,260	1,904,347,099	1,912,878,343	1,933,952,103	1,961,038,264	1,977,854,373	1,995,076,642	2,012,693,177	2,030,717,123	2,049,171,339	2,068,071,608	2,087,435,132
Transmission Plant	211,316,570	214,912,864	216,538,436	218,337,124	223,153,526	234,528,093	249,635,146	258,937,319	259,988,273	262,677,844	269,688,955	276,700,868	286,246,584	299,076,896	312,998,439	328,384,463	345,439,378
Distribution Plant	348,972,022	364,599,823	380,593,018	399,166,810	422,170,659	444,010,162	465,722,308	487,653,309	506,636,261	529,657,172	562,143,916	603,103,886	646,404,198	692,037,891	740,724,213	794,837,337	855,138,098
General Plant	60,278,815	62,156,429	63,643,132	63,616,356	61,373,781	64,348,079	69,193,928	71,973,963	72,751,801	71,470,168	71,763,806	73,428,967	75,228,691	77,182,313	79,252,765	81,510,624	83,980,984
Total Electric Plant	2,438,412,806	2,464,949,491	2,503,033,691	2,547,269,211	2,582,710,650	2,631,595,594	2,688,898,480	2,731,442,933	2,773,328,437	2,824,843,447	2,881,451,051	2,948,310,363	3,020,572,650	3,099,014,222	3,182,146,757	3,272,804,033	3,371,993,592
Yearly Net Additions (Renewals & Replacements)																	
Production Plant																	
Steam Plant	12,444,739	6,060,300	23,938,300	2,624,126	11,612,269	8,675,029	13,819,105	7,895,591	36,331,584	14,482,058	14,876,342	15,252,306	15,622,529	16,016,966	16,421,361	16,835,967	17,261,040
Nuclear Plant	-4,883,527	-2,751,559	10,710,416	10,506,792	-5,015,663	10,121,517	-1,339,973	-3,312,236	890,132	2,055,966	2,063,055	2,066,138	2,067,210	2,070,297	2,073,388	2,076,484	2,079,584
Hydro Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Plant	0	0	0	0	0	0	0	0	342,449	70,134	84,662	102,035	122,852	148,037	178,384	214,953	259,019
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New - CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	7,561,212	3,308,741	34,648,716	13,130,918	6,596,606	18,796,546	12,479,132	4,583,355	37,564,165	16,608,158	17,024,059	17,420,479	17,812,591	18,235,299	18,673,134	19,127,404	19,599,643
Transmission Plant	5,222,327	1,970,261	1,280,884	2,316,492	7,316,311	15,432,823	14,781,283	3,823,063	-1,721,154	7,100,296	6,921,928	7,101,898	11,989,534	13,671,091	14,171,995	16,600,053	17,509,777
Distribution Plant	17,028,277	14,227,325	17,759,065	19,388,519	26,619,180	17,059,826	26,364,466	17,497,536	20,468,367	25,573,455	39,400,034	42,519,906	44,080,717	47,186,669	50,185,976	58,040,273	62,561,249
General Plant	3,942,124	-186,897	3,160,304	-3,213,857	-1,271,292	7,219,888	2,471,809	3,088,262	-1,532,586	-1,030,680	1,617,956	1,712,365	1,887,083	2,020,160	2,120,744	2,394,974	2,545,745
Total Electric Plant	33,753,940	19,319,430	56,848,969	31,622,072	39,260,805	58,509,083	56,096,690	28,992,216	54,778,792	48,251,229	64,963,978	68,754,648	75,769,925	81,113,220	85,151,848	96,162,704	102,216,414
Net Additions/$ Plant																	
Production Plant																	
Steam Plant	0.0272	0.0130	0.0497	0.0053	0.0231	0.0170	0.0264	0.0148	0.0653	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246
Nuclear Plant	-0.0036	-0.0020	0.0079	0.0077	-0.0036	0.0074	-0.0010	-0.0024	0.0006	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
Hydro Plant	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Other Plant	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.0000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000
Total Plant/ $ per U nit																	
Transmission $/KW	83.69	84.95	85.59	86.30	88.21	92.70	98.54	102.20	102.41	104.87	107.60	110.39	113.15	115.98	118.88	121.85	124.90
% Change	4.75%	1.50%	0.76%	0.83%	2.21%	5.10%	6.30%	3.71%	0.21%	2.40%	2.60%	2.60%	2.50%	2.50%	2.50%	2.50%	2.50%
Distribution $/Cust	1,357.89	1,374.42	1,419.22	1,469.60	1,537.95	1,604.78	1,663.13	1,721.22	1,767.36	1,851.98	1,943.31	2,039.15	2,137.67	2,240.95	2,349.23	2,462.73	2,581.72

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
% Change	4.13%	1.22%	3.26%	3.55%	4.65%	4.35%	3.64%	3.49%	2.68%	4.79%	4.93%	4.93%	4.83%	4.83%	4.83%	4.83%	4.83%
General % of Total	2.47%	2.52%	2.54%	2.50%	2.38%	2.45%	2.57%	2.64%	2.62%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%
Depreciation ($)																	
Production Plant																	
Steam Plant	17,079,964	16,194,486	16,234,865	13,105,963	13,547,781	14,880,753	14,861,515	14,449,435	15,331,026	16,050,602	16,455,851	16,871,733	17,297,914	17,734,651	18,182,414	18,641,483	19,112,142
Nuclear Plant	36,533,839	38,679,174	39,515,752	38,956,722	39,522,196	39,790,565	39,693,251	35,917,837	35,925,105	35,944,087	35,997,759	36,051,563	36,105,421	36,159,333	36,213,326	36,267,400	36,321,554
Hydro Plant	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
Other Plant	0	0	0	0	0	0	0	0	4,315	10,036	11,870	14,087	16,760	19,987	23,881	28,578	34,242
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New - CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	53,613,803	54,873,660	55,750,617	52,062,685	53,069,977	54,671,318	54,554,766	50,367,272	51,260,446	52,004,725	52,465,480	52,937,382	53,420,096	53,913,972	54,419,621	54,937,460	55,467,938
Transmission Plant	5,106,843	5,198,613	5,243,407	5,270,851	5,386,430	5,815,063	5,964,997	6,422,384	6,483,326	7,511,384	7,711,870	7,912,378	8,185,342	8,552,230	8,950,323	9,390,292	9,877,985
Distribution Plant	10,396,124	10,835,110	11,324,070	11,967,180	11,872,091	12,882,487	13,587,694	14,335,593	14,805,690	12,884,509	13,674,786	14,671,183	15,724,512	16,834,604	18,018,953	19,335,316	20,802,200
General Plant	3,683,055	3,770,321	3,824,659	2,218,676	2,783,526	2,190,076	2,503,643	2,964,440	3,285,158	2,101,115	2,109,747	2,158,700	2,211,610	2,269,043	2,329,911	2,396,289	2,468,914
Total Electric Plant	72,799,825	74,677,704	76,142,753	71,519,392	73,112,024	75,558,944	76,611,100	74,089,689	75,834,620	74,501,732	75,961,883	77,679,644	79,541,559	81,569,848	83,718,808	86,059,358	88,617,037
Depreciation Factors ($/$ Plant)																	
Production Plant																	
Steam Plant	0.0374	0.0347	0.0337	0.0265	0.0270	0.0291	0.0284	0.0271	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276
Nuclear Plant	0.0268	0.0285	0.0290	0.0284	0.0288	0.0289	0.0287	0.0260	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261
Hydro Plant	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Other Plant	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252
Transmission Plant	0.0295	0.0301	0.0303	0.0279	0.0283	0.0289	0.0286	0.0263	0.0265	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286
Distribution Plant	0.0242	0.0242	0.0242	0.0241	0.0241	0.0248	0.0239	0.0248	0.0249	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243
General Plant	0.0298	0.0297	0.0298	0.0300	0.0281	0.0290	0.0292	0.0294	0.0292	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294
Capital Structure																	
Long Term Debt																	
Total Long-Term Debt (EOY Bal)	933,061,819	954,617,730	912,412,788	999,418,730	1,023,505,015	1,062,957,170	1,108,962,987	1,141,758,545	1,189,916,885	1,185,950,018	1,209,715,507	1,237,784,958	1,268,122,731	1,301,054,745	1,335,956,159	1,374,016,675	1,415,659,287
Long Term Debt as a Percent of Average Gross Plant	38.27%	38.73%	36.45%	39.23%	39.63%	40.39%	41.24%	41.80%	42.91%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%
Cost of Long Term Debt								4.02%		4.40%	4.60%	4.60%	4.50%	4.50%	4.50%	4.50%	4.50%
Proprietary Capital																	
Total Proprietary Cap $ (EOY Bal)	627,330,647	1,137,575,026	1,245,677,616	1,225,203,198	1,186,076,663	1,182,350,803	1,134,478,568	1,138,243,781	1,122,504,726	1,170,785,449	1,194,247,053	1,221,957,583	1,251,907,432	1,284,418,349	1,318,873,484	1,356,447,325	1,397,557,459
Total Proprietary Cap as a Percent of Average Gross Plant	25.73%	46.15%	49.77%	48.10%	45.92%	44.93%	42.19%	41.67%	40.48%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%
Cost of Proprietary Capital										12.40%	12.60%	12.60%	12.50%	12.50%	12.50%	12.50%	12.50%
Weighted Average Cost of Capital										8.37%	8.57%	8.57%	8.47%	8.47%	8.47%	8.47%	8.47%
Taxes																	
Payroll																	
Payroll Expense	40,280,828	38,441,949	29,207,174	36,059,416	35,591,598	34,593,217	35,530,846	38,744,766	41,018,106	40,244,930	41,066,125	41,933,924	42,872,641	43,872,147	44,920,397	46,095,742	47,343,035
Payroll (as % of O&M - Total excluding Fuel and Purchased Power)	19.37%	21.24%	16.99%	21.65%	21.35%	18.10%	16.91%	19.26%	20.67%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%
Payroll Taxes	3,088,986	2,788,087	6,139,830	4,976,550	5,024,267	4,682,863	4,324,600	4,430,531	4,721,107	5,031,230	5,133,892	5,242,380	5,359,734	5,484,688	5,615,735	5,762,671	5,918,602
Payroll Taxes as a Percent of Payroll Expense	7.67%	7.25%	21.02%	13.80%	14.12%	13.54%	12.17%	11.44%	11.51%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Property																	
Average Gross Plant	2,438,412,806	2,464,949,491	2,503,033,691	2,547,269,211	2,582,710,650	2,631,595,594	2,688,898,480	2,731,442,933	2,773,328,437	2,824,843,447	2,881,451,051	2,948,310,363	3,020,572,650	3,099,014,222	3,182,146,757	3,272,804,033	3,371,993,592
Property Tax	32,755,577	37,618,375	39,063,850	40,115,640	41,216,938	41,500,192	35,533,891	33,018,228	34,366,913	35,494,322	36,205,599	37,045,690	37,953,670	38,939,293	39,983,858	41,122,972	42,369,295
Property Tax as a percent of Gross Plant	1.34%	1.53%	1.56%	1.57%	1.60%	1.58%	1.32%	1.21%	1.24%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%
Income																	
Operating Revenue	592,958,037	552,245,591	615,022,376	617,899,972	621,877,043	652,581,028	612,473,006	646,399,546	636,358,943	659,178,823	661,331,825	671,421,794	685,578,274	700,604,395	716,795,593	740,900,673	763,225,295
Less O&M	313,735,398	267,352,683	278,591,011	270,524,895	266,759,147	302,947,389	320,400,443	321,787,680	325,332,216	333,274,097	330,741,112	337,693,976	349,141,535	359,519,437	370,596,004	388,297,251	403,363,453
Less Depreciation	72,799,825	74,677,704	76,142,753	71,519,392	73,112,024	75,558,944	76,611,100	74,089,689	75,834,620	74,501,732	75,961,883	77,679,644	79,541,559	81,569,848	83,718,808	86,059,358	88,617,037
Less Interest Expense	74,319,522	70,968,994	58,616,586	51,500,233	49,432,436	56,218,408	48,664,305	48,287,125	48,539,236	52,181,801	55,646,913	56,938,108	57,065,523	58,547,464	60,118,027	61,830,750	63,704,668
Net Margin	132,103,292	139,246,210	201,672,026	224,355,452	232,573,436	217,856,287	166,797,158	202,235,052	186,652,871	199,221,193	198,981,917	199,110,066	199,829,656	200,967,646	202,362,754	204,713,314	207,540,137
Net Income Taxes Paid	22,876,000	20,569,091	49,123,769	62,639,448	63,549,563	54,882,220	30,266,144	57,489,775	47,098,003	50,260,677	50,200,311	50,232,641	50,414,184	50,701,283	51,053,248	51,646,261	52,359,429

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Net Income Taxes Paid as a percent of Net Margin	17.32%	14.77%	24.36%	27.92%	27.32%	25.19%	18.15%	28.43%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%
Other Income and Deductions ($)																	
Other Income	6,760,659	11,203,389	9,647,165	5,355,485	5,334,196	3,980,288	3,469,682	3,964,643	4,074,619								
Other Income Deductions	11,925,852	-7,396,670	-7,464,122	5,630,430	9,847,503	23,626,505	11,976,251	-3,007,446	9,305,745								
Taxes on Other Income & Deductions	-6,916,153	-187,602	-2,227,296	-7,289,880	-11,762,924	-18,624,098	-12,858,349	-12,518,921	-12,111,127								
Net Other Income and Deductions	1,750,960	18,787,661	19,338,583	7,014,935	7,249,617	-1,022,119	4,351,780	19,491,010	6,880,001	8,436,376	8,655,721	8,880,770	9,102,789	9,330,359	9,563,618	9,802,708	10,047,776
After Tax Margin																	
Net Plant in Service	1,786,773,065	1,742,763,961	1,729,250,929	1,714,467,603	1,691,730,895	1,682,518,796	1,673,204,754	1,640,077,459	1,687,961,943	1,661,711,440	1,650,713,535	1,641,788,538	1,638,016,904	1,637,560,275	1,638,993,315	1,649,096,661	1,662,696,039
After Tax Margin	75,133,689	97,058,318	126,683,160	123,638,749	130,032,285	115,768,893	101,024,303	126,787,528	107,346,849	116,871,339	116,097,835	115,470,123	115,204,857	115,172,742	115,273,530	115,984,118	116,940,588
After Tax Margin as a percent of Net Plant in Service	4.20%	5.57%	7.33%	7.21%	7.69%	6.88%	6.04%	7.73%	6.36%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%
After Tax Margin - $/ MWH Sold	8.68	11.37	12.99	13.07	13.89	10.58	9.75	12.28	9.54	10.22	10.12	10.00	9.92	9.88	9.92	9.88	9.99
Revenue Requirement																	
Operations & Maintenance Expense																	
Production																	
Production Less Fuel	112,561,822	98,183,833	97,676,011	91,549,490	84,985,697	113,504,592	129,134,718	114,535,838	103,649,235	109,908,036	110,858,141	111,830,369	112,824,481	113,842,184	114,884,323	115,951,814	117,045,661
Fuel	105,752,592	86,344,924	106,663,083	103,944,175	100,017,962	111,785,886	110,254,579	120,664,749	126,895,187	129,940,671	123,258,686	125,827,080	129,241,473	129,675,470	129,732,118	135,841,862	134,234,473
Purchased Power										-	-	-	-	-	-	-	-
Purchased Capacity (Maintain 12%)										-	-	-	3,290,395	8,184,395	13,908,139	19,561,334	29,933,099
Subtotal Production	218,314,414	184,528,757	204,339,094	195,493,665	185,003,659	225,290,478	239,389,297	235,200,587	230,544,422	239,848,708	234,116,826	237,657,450	245,356,349	251,702,049	258,524,580	271,355,009	281,213,232
Total Unit Cost - $/ MWH	25.22	21.62	20.96	20.67	19.77	20.59	23.10	22.79	20.49	20.97	20.40	20.58	21.13	21.59	22.25	23.11	24.02
Fuel Unit Cost - $/ MWH	16.14	14.28	12.44	12.02	11.27	12.88	15.47	13.77	11.43	11.93	11.99	12.02	12.06	12.12	12.27	12.26	12.41
Transmission	6,335,975	4,319,648	4,821,351	4,140,745	3,935,581	5,283,935	6,998,210	5,317,970	6,681,532	6,141,931	6,301,621	6,465,463	6,742,064	7,057,459	7,384,409	7,767,376	8,171,330
Distribution	15,242,835	15,248,972	15,487,031	14,356,822	16,376,637	16,220,314	16,348,945	19,035,520	20,097,404	21,049,148	22,578,038	24,227,992	25,938,513	27,769,558	29,716,989	31,969,200	34,396,845
General	73,842,174	63,255,306	53,943,535	56,533,663	61,443,270	56,152,662	57,663,991	62,233,603	68,008,858	66,234,311	67,744,627	69,343,071	71,104,609	72,990,371	74,970,026	77,205,666	79,582,046
Total Operation & Maintenance Expense	313,735,398	267,352,683	278,591,011	270,524,895	266,759,147	302,947,389	320,400,443	321,787,680	325,332,216	333,274,097	330,741,112	337,693,976	349,141,535	359,519,437	370,596,004	388,297,251	403,363,453
Depreciation	72,799,825	74,677,704	76,142,753	71,519,392	73,112,024	75,558,944	76,611,100	74,089,689	75,834,620	74,501,732	75,961,883	77,679,644	79,541,559	81,569,848	83,718,808	86,059,358	88,617,037
Interest Expense	74,319,522	70,968,994	58,616,586	51,500,233	49,432,436	56,218,408	48,664,305	48,287,125	48,539,236	52,181,801	55,646,913	56,938,108	57,065,523	58,547,464	60,118,027	61,830,750	63,704,668
Payroll Taxes	3,088,986	2,788,087	6,139,830	4,976,550	5,024,267	4,682,863	4,324,600	4,430,531	4,721,107	5,031,230	5,133,892	5,242,380	5,359,734	5,484,688	5,615,735	5,762,671	5,918,602
Property Taxes	32,755,577	37,618,375	39,063,850	40,115,640	41,216,938	41,500,192	35,533,891	33,018,228	34,366,913	35,494,322	36,205,599	37,045,690	37,953,670	38,939,293	39,983,858	41,122,972	42,369,295
Net Income Taxes	22,876,000	20,569,091	49,123,769	62,639,448	63,549,563	54,882,220	30,266,144	57,489,775	47,098,003	50,260,677	50,200,311	50,232,641	50,414,184	50,701,283	51,053,248	51,646,261	52,359,429
Other	-1,750,960	-18,787,661	-19,338,583	-7,014,935	-7,249,617	1,022,119	-4,351,780	-19,491,010	-6,880,001	-8,436,376	-8,655,721	-8,880,770	-9,102,789	-9,330,359	-9,563,618	-9,802,708	-10,047,776
Margin	75,133,689	97,058,318	126,683,160	123,638,749	130,032,285	115,768,893	101,024,303	126,787,528	107,346,849	116,871,339	116,097,835	115,470,123	115,204,857	115,172,742	115,273,530	115,984,118	116,940,588
Total KG&E Revenue Requirement	592,958,037	552,245,591	615,022,376	617,899,972	621,877,043	652,581,028	612,473,006	646,399,546	636,358,943	659,178,823	661,331,825	671,421,794	685,578,274	700,604,395	716,795,593	740,900,673	763,225,295
Sales (MWH)																	
Retail	7,488,497	7,287,278	7,744,969	7,867,868	8,066,643	8,235,237	8,263,674	8,781,628	8,419,212	8,602,411	8,793,576	8,992,706	9,183,870	9,379,018	9,574,165	9,825,069	10,083,937
Wholesale	1,168,178	1,249,113	2,004,107	1,589,974	1,292,203	2,705,930	2,100,888	1,540,546	2,833,344	2,834,256	2,683,274	2,555,863	2,428,350	2,277,152	2,046,031	1,917,085	1,624,525
Total Sales (MWH)	8,656,675	8,536,391	9,749,076	9,457,842	9,358,846	10,941,167	10,364,562	10,322,174	11,252,556	11,436,667	11,476,849	11,548,568	11,612,220	11,656,169	11,620,196	11,742,153	11,708,462
Total KG&E Revenue Requirement - $/MWH	68.50	64.69	63.09	65.33	66.45	59.64	59.09	62.62	56.55	57.64	57.62	58.14	59.04	60.11	61.69	63.10	65.19
Less Cosr of Service of Off System Sales																	
Fuel	18,854,381	17,833,257	24,923,476	19,103,685	14,565,236	34,844,128	32,490,637	21,218,181	32,394,964	33,809,001	32,171,634	30,720,789	29,286,168	27,605,944	25,108,618	23,498,189	20,157,891
O&M	1,504,951	1,609,219	2,581,870	2,048,347	1,664,731	3,486,021	2,706,552	1,984,669	3,650,167	3,651,342	3,456,833	3,378,797	3,288,001	3,152,906	2,899,448	2,785,909	2,412,644
Demand Charge (Fixed Cost Recovery)		2,041,000	2,362,216	4,147,650	5,879,038	7,282,418	7,937,244	8,892,773	16,355,425	16,360,692	15,489,147	14,753,669	14,017,603	13,144,816	11,810,677	11,066,337	9,377,540
Margin	17,925,732	2,580,206	17,835,835	17,773,854	17,275,746	21,937,225	20,382,710	33,311,415	37,551,554	42,683,660	41,828,520	41,700,643	42,672,829	43,941,384	43,647,591	43,428,972	40,660,108
Total Cost of Off System Sales	38,285,064	24,063,682	47,703,397	43,073,536	39,384,752	67,549,792	63,517,142	65,407,038	89,952,110	96,504,695	92,946,134	90,553,898	89,264,601	87,845,050	83,466,334	80,779,406	72,608,184
Wholesale KG&E Revenue Requirement - $/MWH	32.77	19.26	23.80	27.09	30.48	24.96	30.23	42.46	31.75	34.05	34.64	35.43	36.76	38.58	40.79	42.14	44.70
Retail KG&E Revenue Requirement - $/MWH	554,672,973	528,181,909	567,318,979	574,826,436	582,492,291	585,031,236	548,955,864	580,992,508	546,406,833	562,674,128	568,385,692	580,867,895.47	596,313,672	612,759,345	633,329,259	660,121,267	690,617,111
Retail KG&E Revenue Requirement - $/MWH	74.07	72.48	73.25	73.06	72.21	71.04	66.43	66.16	64.90	65.41	64.64	64.59	64.93	65.33	66.15	67.19	68.49
KG&E - Average Rate ($/MWh)	74.07	72.48	73.25	73.06	72.21	71.04	66.43	66.16	64.90	65.41	64.64	64.59	64.93	65.33	66.15	67.19	68.49
Residential	93.96	92.38	91.82	92.31	92.94	90.48	86.24	85.33	84.80	85.46	84.46	84.40	84.84	85.37	86.43	87.79	89.49
Commercial	81.69	81.38	81.81	81.00	81.94	80.94	73.68	71.53	70.20	70.75	69.91	69.87	70.23	70.67	71.55	72.67	74.08
Industrial	54.14	53.64	53.94	53.73	51.65	50.11	47.08	46.89	46.00	46.36	45.81	45.78	46.02	46.31	46.89	47.62	48.54

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Street Light / Hwy	129.68	128.53	135.70	136.65	138.21	137.78	125.96	123.01	123.00	123.96	122.50	122.42	123.06	123.82	125.37	127.34	129.80
KG&E - Average Rate ($/MWh) - with 5% Franchise Fee	77.77	76.10	76.91	76.71	75.82	74.59	69.75	69.47	68.15	68.68	67.87	67.82	68.18	68.60	69.46	70.55	71.91
Residential	98.66	97.00	96.41	96.93	97.59	95.00	90.55	89.60	89.04	89.74	88.68	88.62	89.08	89.63	90.75	92.18	93.96
Commercial	85.77	85.45	85.90	85.05	86.04	84.99	77.36	75.11	73.71	74.29	73.41	73.36	73.74	74.20	75.13	76.31	77.78
Industrial	56.85	56.32	56.64	56.42	54.23	52.62	49.43	49.23	48.30	48.68	48.10	48.07	48.32	48.62	49.23	50.00	50.97
Street Light / Hwy	136.16	134.96	142.49	143.48	145.12	144.67	132.26	129.16	129.15	130.16	128.63	128.54	129.21	130.01	131.64	133.70	136.29

Projected Operating Results

Kansas Gas and Electric (KGE a WRI Company)

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
Market Prices														
All In Energy Price - $/MWH	46.11	47.56	49.02	50.36	52.09	53.39	54.62	55.76	56.81	57.76	58.61	59.36	60.11	60.88
Percent Change	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	1%	1%	1%	1%
Energy Only Price - $/MWH	$35.08	$36.19	$37.16	$38.57	$39.15	$40.13	$41.05	$41.91	$42.70	$43.41	$44.05	$44.61	$45.18	$45.75
Percent Change	5.67%	3.17%	2.68%	3.79%	1.51%	2.50%	2.29%	2.09%	1.88%	1.68%	1.47%	1.27%	1.27%	1.27%
Capacity - $/KW-yr	$96.67	$99.63	$103.91	$103.36	$113.35	$116.18	$118.85	$121.33	$123.62	$125.70	$127.55	$129.17	$130.81	$132.47
$/Kwh	$11.04	$11.37	$11.86	$11.80	$12.94	$13.26	$13.57	$13.85	$14.11	$14.35	$14.56	$14.75	$14.93	$15.12
System Capacity Requirements														
System Peak (MW)	2,595	2,662	2,731	2,801	2,873	2,948	3,024	3,102	3,182	3,264	3,348	3,435	3,523	3,614
System Peak (MW) - EIA Form 411 10 Yr														
~~Total System Capacity (MW)~~	2590													
Existing Capacity	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539	2,539
Capacity Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Capacity Additions - Cumulative Total	368	443	520	599	680	763	848	935	1,025	1,117	1,211	1,308	1,407	1,510
Total Capacity	2,906	2,981	3,058	3,137	3,218	3,301	3,387	3,474	3,564	3,656	3,750	3,847	3,946	4,050
~~Reserve Capacity Calculation (MW)~~														
RM Calculation for Additional Capacity														
System Peak (MW)	2,595	2,662	2,731	2,801	2,873	2,948	3,024	3,102	3,182	3,264	3,348	3,435	3,523	3,614
Reserve Margin	311	319	328	336	345	354	363	372	382	392	402	412	423	434
Total requirements	2,906	2,981	3,058	3,137	3,218	3,301	3,387	3,474	3,564	3,656	3,750	3,847	3,946	4,048
Surplus Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Required Reserves	311	319	328	336	345	354	363	372	382	392	402	412	423	434
Required Reserves form Surplus	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Required Reserves form Market	311	319	328	336	345	354	363	372	382	392	402	412	423	434
Reserve Margin	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
System Energy Requirements														
~~MWH Sales - Retail~~														
Residential Sales	3,150,981	3,232,313	3,315,745	3,401,331	3,489,126	3,579,187	3,671,572	3,766,342	3,863,559	3,963,284	4,065,584	4,170,525	4,278,174	4,388,601
% of Total Retail	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%	30.5%
Commercial Sales	2,693,314	2,762,833	2,834,147	2,907,302	2,982,345	3,059,324	3,138,291	3,219,297	3,302,393	3,387,634	3,475,075	3,564,773	3,656,786	3,751,175
% of Total Retail	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%
Industrial Sales	4,429,145	4,543,470	4,660,745	4,781,048	4,904,455	5,031,049	5,160,909	5,294,122	5,430,773	5,570,952	5,714,749	5,862,257	6,013,573	6,168,794
% of Total Retail	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%	42.9%
Public Street & Highway Lighting	61,402	62,987	64,612	66,280	67,991	69,746	71,546	73,393	75,287	77,231	79,224	81,269	83,367	85,519
% of Total Retail	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Other														
Total Retail	10,334,841	10,601,603	10,875,250	11,155,961	11,443,917	11,739,306	12,042,319	12,353,154	12,672,012	12,999,101	13,334,632	13,678,824	14,031,900	14,394,090
% Change Per Year	2.5%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Distribution Losses	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
Retail NEFL	10,874,300	11,154,987	11,442,918	11,738,281	12,041,268	12,352,076	12,670,906	12,997,966	13,333,468	13,677,629	14,030,675	14,392,833	14,764,339	15,145,434
Net Generation (Projected Per Prosym)														
Generating Stations	12,844,583	12,791,776	12,748,327	12,728,922	12,791,333	12,813,394	12,813,394	12,813,394	12,813,394	12,813,394	12,813,394	12,813,394	12,813,394	12,813,394
Purchased Power	0	0	0	0	0	0	0	184,572	520,073	864,235	1,217,281	1,579,439	1,950,945	2,332,040
Exchanges - Net	(491,342)	(408,177)	(325,538)	(247,042)	(187,048)	(115,042)	(35,533)	-	-	-	-	-	-	-
Wheeling - Net														
Total Sources	12,353,241	12,383,600	12,422,789	12,481,879	12,604,285	12,698,352	12,777,861	12,997,966	13,333,468	13,677,629	14,030,675	14,392,833	14,764,339	15,145,434
MWH Sales - Wholesale	1,478,941	1,228,613	979,871	743,598	563,017	346,277	106,955	-	-	-	-	-	-	-
Annual System Load Factor - Sales	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%	47.8%
Historical Losses %														
Number of Customers														
Residential	315,998	324,154	332,521	341,104	349,909	358,941	368,206	377,710	387,459	397,460	407,719	418,243	429,039	440,113
Commercial	31,533	32,347	33,182	34,038	34,917	35,818	36,743	37,691	38,664	39,662	40,686	41,736	42,813	43,919
Industrial	4,356	4,468	4,583	4,702	4,823	4,948	5,075	5,206	5,341	5,479	5,620	5,765	5,914	6,066
Public Street & Highway Lighting														
Total Retail	351,887	360,970	370,287	379,845	389,649	399,707	410,024	420,607	431,464	442,601	454,025	465,745	477,766	490,098
% Change Per Year	2.5%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%
Usage Per Customer (MWH/Customer)														
Residential Sales	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Commercial Sales	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4	85.4
Industrial Sales	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9	1016.9
Public Street & Highway Lighting	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Retail	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4
Retail Rate - Historical														
Average Rate														
Residential Sales														
Commercial Sales														
Industrial Sales														
Public Street & Highway Lighting														
Total Retail														
Plant in Service														
EOY Gross Plant in Service														
Production Plant														
Steam Plant	718,619,283	736,762,938	755,364,683	774,436,083	793,988,997	814,035,581	834,588,301	855,659,934	877,263,583	899,412,679	922,120,994	945,402,647	969,272,114	993,744,236
Nuclear Plant	1,396,872,681	1,398,958,481	1,401,047,395	1,403,139,428	1,405,234,585	1,407,332,871	1,409,434,289	1,411,538,846	1,413,646,545	1,415,757,391	1,417,871,389	1,419,988,544	1,422,108,860	1,424,232,342
Hydro Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Plant	1,834,642	2,210,744	2,663,946	3,210,055	3,868,117	4,661,081	5,616,602	6,768,006	8,155,447	9,827,314	11,841,913	14,269,505	17,194,753	20,719,678
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New -CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	2,117,326,607	2,137,932,163	2,159,076,024	2,180,785,566	2,203,091,699	2,226,029,533	2,249,639,192	2,273,966,785	2,299,065,574	2,324,997,383	2,351,834,296	2,379,660,696	2,408,575,727	2,438,696,255
Transmission Plant	372,082,336	391,228,641	411,360,161	432,527,593	454,784,240	478,186,152	502,792,260	528,664,528	555,868,111	584,471,513	614,546,765	646,169,604	679,419,666	714,733,640
Distribution Plant	952,368,153	1,024,153,067	1,101,348,782	1,184,363,137	1,273,634,713	1,369,635,150	1,472,871,637	1,583,889,592	1,703,275,544	1,831,660,233	1,969,721,940	2,118,190,072	2,277,849,015	2,449,542,279
General Plant	87,908,369	90,757,193	93,783,130	96,998,592	100,416,930	104,052,521	107,920,849	112,038,604	116,423,792	121,095,852	126,075,790	131,386,325	137,052,057	143,108,671
Total Electric Plant	3,529,685,465	3,644,071,064	3,765,568,097	3,894,674,888	4,031,927,582	4,177,903,356	4,333,223,937	4,498,559,509	4,674,633,020	4,862,224,980	5,062,178,790	5,275,406,696	5,502,896,465	5,746,080,846
Accumulated Depreciation (EOY)														
Production Plant														
Steam Plant	488,332,678	508,422,087	529,018,713	550,135,360	571,785,160	593,981,572	616,738,399	640,069,787	663,990,246	688,514,647	713,658,238	739,436,653	765,865,920	792,962,471

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Nuclear Plant	786,321,505	822,751,610	859,236,112	895,775,093	932,368,633	969,016,814	1,005,719,719	1,042,477,427	1,079,290,023	1,116,157,586	1,153,080,200	1,190,057,946	1,227,090,907	1,264,179,166
Hydro Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Plant	204,828	254,136	313,372	384,577	470,207	573,224	697,198	846,426	1,026,092	1,242,438	1,502,987	1,816,806	2,194,817	2,650,183
New - CT														
New - CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Production Plant	1,274,859,010	1,331,427,833	1,388,568,197	1,446,295,030	1,504,624,000	1,563,571,611	1,623,155,315	1,683,393,641	1,744,306,360	1,805,914,670	1,868,241,425	1,931,311,405	1,995,151,644	2,059,791,820
Transmission Plant	183,784,024	194,697,624	206,172,807	218,238,470	230,924,999	244,264,340	258,290,086	273,037,557	288,543,892	304,848,138	321,991,355	340,016,714	358,969,606	378,902,808
Distribution Plant	342,679,167	366,719,723	392,572,340	420,373,602	450,270,389	482,420,652	516,994,247	554,173,832	594,155,834	637,151,488	683,387,945	733,109,484	786,578,793	844,078,360
General Plant	50,389,835	53,016,083	55,728,686	58,533,033	61,434,892	64,440,438	67,556,286	70,789,523	74,147,747	77,639,106	81,272,342	85,056,840	89,002,681	93,120,831
Total Electric Plant	1,851,712,036	1,945,861,263	2,043,042,030	2,143,440,135	2,247,254,280	2,354,697,041	2,465,995,933	2,581,394,553	2,701,153,834	2,825,553,402	2,954,893,068	3,089,494,443	3,229,702,724	3,375,893,819
Net Plant In Service (EOY)														
Production Plant														
Steam Plant	230,286,605	228,340,851	226,345,970	224,300,722	222,203,837	220,054,009	217,849,902	215,590,147	213,273,337	210,898,032	208,462,756	205,965,994	203,406,195	200,781,765
Nuclear Plant	610,551,176	576,206,871	541,811,283	507,364,335	472,865,952	438,316,056	403,714,571	369,061,418	334,356,522	299,599,805	264,791,189	229,930,597	195,017,952	160,053,176
Hydro Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Plant	1,629,814	1,956,608	2,350,574	2,825,479	3,397,910	4,087,856	4,919,405	5,921,579	7,129,355	8,584,876	10,338,925	12,452,699	14,999,937	18,069,495
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New - CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	842,467,596	806,504,330	770,507,827	734,490,536	698,467,699	662,457,921	626,483,878	590,573,144	554,759,214	519,082,713	483,592,871	448,349,291	413,424,083	378,904,436
Transmission Plant	188,298,312	196,531,017	205,187,355	214,289,122	223,859,242	233,921,812	244,502,174	255,626,971	267,324,219	279,623,374	292,555,409	306,152,890	320,450,059	335,830,833
Distribution Plant	609,688,986	657,433,344	708,776,442	763,989,535	823,364,324	887,214,498	955,877,390	1,029,715,760	1,109,119,709	1,194,508,745	1,286,333,994	1,385,080,587	1,491,270,222	1,605,463,919
General Plant	37,518,534	37,741,110	38,054,444	38,465,558	38,982,039	39,612,083	40,364,563	41,249,081	42,276,045	43,456,746	44,803,448	46,329,485	48,049,377	49,987,840
Total Electric Plant	1,677,973,428	1,698,209,801	1,722,526,067	1,751,234,752	1,784,673,303	1,823,206,315	1,867,228,005	1,917,164,956	1,973,479,187	2,036,671,578	2,107,285,722	2,185,912,253	2,273,193,742	2,370,187,027
Average Balance - Gross Plant in Service														
Production Plant														
Steam Plant	709,770,860	727,691,110	746,063,810	764,900,383	784,212,540	804,012,289	824,311,941	845,124,117	866,461,758	888,338,131	910,766,836	933,761,821	957,337,381	981,508,175
Nuclear Plant	1,395,831,336	1,397,915,581	1,400,002,938	1,402,093,411	1,404,187,007	1,406,283,728	1,408,383,580	1,410,486,567	1,412,592,695	1,414,701,968	1,416,814,390	1,418,929,966	1,421,048,702	1,423,170,601
Hydro Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Plant	1,678,583	2,022,693	2,437,345	2,937,001	3,539,086	4,264,599	5,138,841	6,192,304	7,461,726	8,991,380	10,834,613	13,055,709	15,732,129	18,957,216
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New - CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	2,107,280,780	2,127,629,385	2,148,504,093	2,169,930,795	2,191,938,632	2,214,560,616	2,237,834,362	2,261,802,989	2,286,516,180	2,312,031,479	2,338,415,839	2,365,747,496	2,394,118,211	2,423,635,991
Transmission Plant	363,138,301	381,655,489	401,294,401	421,943,877	443,655,916	466,485,196	490,489,206	515,728,394	542,266,319	570,169,812	599,509,139	630,358,184	662,794,635	697,076,653
Distribution Plant	919,393,438	988,260,610	1,062,750,925	1,142,855,959	1,228,998,925	1,321,634,932	1,421,253,394	1,528,380,614	1,643,582,568	1,767,467,888	1,900,691,086	2,043,956,006	2,198,019,543	2,363,695,647
General Plant	86,581,113	89,332,781	92,270,162	95,390,861	98,707,761	102,234,726	105,986,685	109,979,726	114,231,198	118,759,822	123,585,821	128,731,057	134,219,191	140,080,364
Total Electric Plant	3,476,393,632	3,586,878,264	3,704,819,581	3,830,121,492	3,963,301,235	4,104,915,469	4,255,563,647	4,415,891,723	4,586,596,265	4,768,429,000	4,962,201,885	5,168,792,743	5,389,151,581	5,624,488,656
Yearly Net Additions (Renewals & Replacements)														
Production Plant														
Steam Plant	17,696,846	18,143,655	18,601,745	19,071,400	19,552,914	20,046,585	20,552,720	21,071,633	21,603,649	22,149,096	22,708,315	23,281,653	23,869,467	24,472,122
Nuclear Plant	2,082,690	2,085,800	2,088,914	2,092,033	2,095,157	2,098,285	2,101,419	2,104,556	2,107,699	2,110,846	2,113,998	2,117,155	2,120,316	2,123,482
Hydro Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Plant	312,118	376,102	453,202	546,109	658,061	792,964	955,522	1,151,403	1,387,441	1,671,867	2,014,599	2,427,592	2,925,249	3,524,924
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New - CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	20,091,653	20,605,556	21,143,861	21,709,543	22,306,132	22,937,834	23,609,660	24,327,593	25,098,789	25,931,809	26,836,912	27,826,400	28,915,031	30,120,528
Transmission Plant	17,888,069	19,146,305	20,131,520	21,167,431	22,256,647	23,401,912	24,606,108	25,872,269	27,203,582	28,603,402	30,075,252	31,622,840	33,250,062	35,313,974
Distribution Plant	65,949,430	71,784,914	77,195,715	83,014,355	89,271,576	96,000,437	103,236,487	111,017,955	119,385,952	128,384,689	138,061,707	148,468,132	159,658,943	171,693,264
General Plant	2,654,513	2,848,824	3,025,937	3,215,461	3,418,339	3,635,591	3,868,327	4,117,755	4,385,188	4,672,060	4,979,938	5,310,535	5,665,733	6,056,614
Total Electric Plant	106,583,666	114,385,599	121,497,033	129,106,790	137,252,695	145,975,773	155,320,581	165,335,572	176,073,512	187,591,960	199,953,809	213,227,907	227,489,769	243,184,380
Net Additions/$ Plant														
Production Plant														
Steam Plant	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246
Nuclear Plant	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
Hydro Plant	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Other Plant	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000
Total Plant/ $ per U nit														
Transmission $/KW	128.02	131.22	134.50	137.87	141.31	144.84	148.47	152.18	155.98	159.88	163.88	167.98	172.17	176.48
% Change	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Distribution $/Cust	2,706.46	2,837.23	2,974.31	3,118.02	3,268.67	3,426.60	3,592.16	3,765.72	3,947.66	4,138.40	4,338.35	4,547.96	4,767.71	4,998.06

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
% Change	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%
General % of Total	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%

Depreciation ($)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Production Plant														
Steam Plant	19,594,684	20,089,409	20,596,626	21,116,648	21,649,800	22,196,412	22,756,826	23,331,389	23,920,458	24,524,401	25,143,591	25,778,415	26,429,267	27,096,551
Nuclear Plant	36,375,789	36,430,105	36,484,502	36,538,981	36,593,540	36,648,182	36,702,904	36,757,709	36,812,595	36,867,563	36,922,614	36,977,746	37,032,961	37,088,259
Hydro Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Plant	41,073	49,308	59,236	71,204	85,630	103,017	123,973	149,229	179,666	216,346	260,550	313,818	378,011	455,366
New - CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New - CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Plant	56,011,546	56,568,823	57,140,364	57,726,833	58,328,970	58,947,611	59,583,703	60,238,326	60,912,719	61,608,310	62,326,754	63,069,980	63,840,239	64,640,176
Transmission Plant	10,384,093	10,913,600	11,475,183	12,065,663	12,686,528	13,339,341	14,025,746	14,747,471	15,506,334	16,304,247	17,143,217	18,025,359	18,952,893	19,933,201
Distribution Plant	22,365,284	24,040,556	25,852,617	27,801,262	29,896,787	32,150,263	34,573,594	37,179,585	39,982,003	42,995,653	46,236,458	49,721,539	53,469,309	57,499,567
General Plant	2,545,354	2,626,248	2,712,603	2,804,347	2,901,859	3,005,546	3,115,848	3,233,237	3,358,224	3,491,359	3,633,236	3,784,498	3,945,841	4,118,150
Total Electric Plant	91,306,276	94,149,227	97,180,767	100,398,105	103,814,144	107,442,761	111,298,892	115,398,620	119,759,281	124,399,569	129,339,665	134,601,375	140,208,281	146,191,095

Depreciation Factors ($/$ Plant)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Production Plant														
Steam Plant	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276
Nuclear Plant	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261	0.0261
Hydro Plant	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
Other Plant	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252	0.0252
Transmission Plant	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286	0.0286
Distribution Plant	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243	0.0243
General Plant	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294

Capital Structure

Long Term Debt

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Long-Term Debt (EOY Bal)	1,459,489,407	1,505,874,014	1,555,389,149	1,607,994,473	1,663,907,136	1,723,360,839	1,786,607,249	1,853,917,558	1,925,584,204	2,001,922,783	2,083,274,179	2,170,006,926	2,262,519,864	2,361,321,094
Long Term Debt as a Percent of Average Gross Plant	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%	41.98%
Cost of Long Term Debt	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

Proprietary Capital

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Proprietary Cap $ (EOY Bal)	1,440,827,131	1,486,618,624	1,535,500,617	1,587,433,284	1,642,631,000	1,701,324,477	1,763,762,165	1,830,211,787	1,900,962,041	1,976,324,491	2,056,635,658	2,142,259,366	2,233,589,355	2,331,127,228
Total Proprietary Cap as a Percent of Average Gross Plant	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%	41.45%
Cost of Proprietary Capital	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Weighted Average Cost of Capital	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%	8.47%

Taxes

Payroll

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Payroll Expense	48,643,610	50,036,325	51,513,765	53,081,890	54,747,119	56,516,375	58,397,125	60,397,437	62,526,025	64,792,323	67,206,545	69,779,769	72,524,025	75,455,666
Payroll (as % of O&M - Total excluding Fuel and Purchased Power)	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%	19.79%
Payroll Taxes	6,081,193	6,255,304	6,440,007	6,636,046	6,844,225	7,065,409	7,300,532	7,550,601	7,816,707	8,100,029	8,401,843	8,723,536	9,066,610	9,433,110
Payroll Taxes as a Percent of Payroll Expense	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%

Property

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Average Gross Plant	3,476,393,632	3,586,878,264	3,704,819,581	3,830,121,492	3,963,301,235	4,104,915,469	4,255,563,647	4,415,891,723	4,586,596,265	4,768,429,000	4,962,201,885	5,168,792,743	5,389,151,581	5,624,488,656
Property Tax	43,681,087	45,069,333	46,551,273	48,125,698	49,799,110	51,578,501	53,471,404	55,485,935	57,630,848	59,915,587	62,350,354	64,946,180	67,715,002	70,672,026
Property Tax as a percent of Gross Plant	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%

Income

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Operating Revenue	786,880,268	812,687,534	841,174,799	869,144,759	907,265,415	943,668,612	982,078,370	1,032,854,469	1,094,740,944	1,159,977,447	1,228,581,228	1,300,566,747	1,376,900,139	1,458,046,645
Less O&M	419,283,895	436,512,258	455,576,525	473,255,440	500,153,040	524,332,199	549,442,502	585,763,351	631,951,910	680,153,857	730,284,696	782,248,597	836,892,018	894,504,417
Less Depreciation	91,306,276	94,149,227	97,180,767	100,398,105	103,814,144	107,442,761	111,298,892	115,398,620	119,759,281	124,399,569	129,339,665	134,601,375	140,208,281	146,191,095
Less Interest Expense	65,677,023	67,764,331	69,992,512	72,359,751	74,875,821	77,551,238	80,397,326	83,426,290	86,651,289	90,086,525	93,747,338	97,650,312	101,813,394	106,259,449
Net Margin	210,613,073	214,261,719	218,424,995	223,131,463	228,422,409	234,342,415	240,939,650	248,266,207	256,378,464	265,337,496	275,209,529	286,066,463	297,986,446	311,091,684
Net Income Taxes Paid	53,134,687	54,055,188	55,105,524	56,292,899	57,627,729	59,121,263	60,785,651	62,634,038	64,680,645	66,940,881	69,431,455	72,170,505	75,177,748	78,484,013

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Net Income Taxes Paid as a percent of Net Margin	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%	25.23%
Other Income and Deductions ($)														
Other Income														
Other Income Deductions														
Taxes on Other Income & Deductions														
Net Other Income and Deductions	10,298,971	10,556,445	10,820,356	11,090,865	11,368,136	11,652,340	11,943,648	12,242,240	12,548,296	12,862,003	13,183,553	13,513,142	13,850,970	14,197,245
After Tax Margin														
Net Plant in Service	1,677,973,428	1,698,209,801	1,722,526,067	1,751,234,752	1,784,673,303	1,823,206,315	1,867,228,005	1,917,164,956	1,973,479,187	2,036,671,578	2,107,285,722	2,185,912,253	2,273,193,742	2,370,187,027
After Tax Margin	118,015,076	119,438,339	121,148,548	123,167,685	125,519,482	128,229,582	131,325,712	134,837,873	138,798,560	143,243,002	148,209,429	153,739,383	159,878,057	166,699,780
After Tax Margin as a percent of Net Plant in Service	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%
After Tax Margin - $/ MWH Sold	9.99	10.10	10.22	10.35	10.45	10.61	10.81	10.92	10.95	11.02	11.11	11.24	11.39	11.58
Revenue Requirement														
Operations & Maintenance Expense														
Production														
Production Less Fuel	118,166,966	119,316,952	120,496,981	121,708,580	122,953,474	124,233,623	125,551,267	126,908,978	128,309,729	129,756,971	131,254,726	132,807,704	134,421,437	136,102,449
Fuel	137,970,017	139,596,728	141,307,077	143,188,388	146,513,793	150,176,638	153,623,191	156,833,916	159,790,235	162,474,711	164,871,213	166,965,078	169,085,534	171,232,921
Purchased Power	-	-	-	-	-	-	-	10,291,237	29,544,576	49,920,694	71,350,722	93,754,312	117,277,380	141,966,575
Purchased Capacity (Maintain 12%)	35,546,978	44,112,076	54,001,377	61,876,191	77,034,985	88,612,314	100,773,761	113,486,280	126,710,702	140,401,817	154,508,512	168,974,004	184,108,830	200,072,825
Subtotal Production	291,683,960	303,025,756	315,805,435	326,773,158	346,502,252	363,022,575	379,948,220	407,520,411	444,355,243	482,554,193	521,985,174	562,501,098	604,893,182	649,374,770
Total Unit Cost - $/ MWH	24.69	25.61	26.64	27.46	28.86	30.04	31.27	32.99	35.07	37.12	39.15	41.12	43.11	45.11
Fuel Unit Cost - $/ MWH	12.42	12.52	12.62	12.70	12.71	12.76	12.83	12.75	12.57	12.39	12.22	12.05	11.89	11.74
Transmission	8,584,011	9,025,720	9,490,158	9,978,495	10,491,960	11,031,846	11,599,514	12,196,392	12,823,984	13,483,870	14,177,712	14,907,257	15,674,342	16,489,042
Distribution	36,955,965	39,741,527	42,737,052	45,958,365	49,422,484	53,147,713	57,153,731	61,461,703	66,094,389	71,076,265	76,433,651	82,194,851	88,390,302	95,052,736
General	82,059,959	84,719,254	87,543,881	90,545,422	93,736,344	97,130,065	100,741,038	104,584,845	108,678,293	113,039,529	117,688,159	122,645,392	127,934,192	133,587,868
Total Operation & Maintenance Expense	419,283,895	436,512,258	455,576,525	473,255,440	500,153,040	524,332,199	549,442,502	585,763,351	631,951,910	680,153,857	730,284,696	782,248,597	836,892,018	894,504,417
Depreciation	91,306,276	94,149,227	97,180,767	100,398,105	103,814,144	107,442,761	111,298,892	115,398,620	119,759,281	124,399,569	129,339,665	134,601,375	140,208,281	146,191,095
Interest Expense	65,677,023	67,764,331	69,992,512	72,359,751	74,875,821	77,551,238	80,397,326	83,426,290	86,651,289	90,086,525	93,747,338	97,650,312	101,813,394	106,259,449
Payroll Taxes	6,081,193	6,255,304	6,440,007	6,636,046	6,844,225	7,065,409	7,300,532	7,550,601	7,816,707	8,100,029	8,401,843	8,723,536	9,066,610	9,433,110
Property Taxes	43,681,087	45,069,333	46,551,273	48,125,698	49,799,110	51,578,501	53,471,404	55,485,935	57,630,848	59,915,587	62,350,354	64,946,180	67,715,002	70,672,026
Net Income Taxes	53,134,687	54,055,188	55,105,524	56,292,899	57,627,729	59,121,263	60,785,651	62,634,038	64,680,645	66,940,881	69,431,455	72,170,505	75,177,748	78,484,013
Other	-10,298,971	-10,556,445	-10,820,356	-11,090,865	-11,368,136	-11,652,340	-11,943,648	-12,242,240	-12,548,296	-12,862,003	-13,183,553	-13,513,142	-13,850,970	-14,197,245
Margin	118,015,076	119,438,339	121,148,548	123,167,685	125,519,482	128,229,582	131,325,712	134,837,873	138,798,560	143,243,002	148,209,429	153,739,383	159,878,057	166,699,780
Total KG&E Revenue Requirement	786,880,268	812,687,534	841,174,799	869,144,759	907,265,415	943,668,612	982,078,370	1,032,854,469	1,094,740,944	1,159,977,447	1,228,581,228	1,300,566,747	1,376,900,139	1,458,046,645
Sales (MWH)														
Retail	10,334,841	10,601,603	10,875,250	11,155,961	11,443,917	11,739,306	12,042,319	12,353,154	12,672,012	12,999,101	13,334,632	13,678,824	14,031,900	14,394,090
Wholesale	1,478,941	1,228,613	979,871	743,598	563,017	346,277	106,955	-	-	-	-	-	-	-
Total Sales (MWH)	11,813,782	11,830,216	11,855,121	11,899,559	12,006,934	12,085,583	12,149,275	12,353,154	12,672,012	12,999,101	13,334,632	13,678,824	14,031,900	14,394,090
Total KG&E Revenue Requirement - $/MWH	66.61	68.70	70.95	73.04	75.56	78.08	80.83	83.61	86.39	89.24	92.13	95.08	98.13	101.29
Less Cosr of Service of Off System Sales														
Fuel	18,362,048	15,381,118	12,362,392	9,440,436	7,156,378	4,418,329	1,371,941	-	-	-	-	-	-	-
O&M	2,253,215	1,919,737	1,568,478	1,218,744	945,530	595,724	188,491	-	-	-	-	-	-	-
Demand Charge (Fixed Cost Recovery)	8,537,157	7,092,147	5,656,289	4,292,408	3,250,004	1,998,876	617,396	-	-	-	-	-	-	-
Margin	39,044,381	34,042,279	28,444,989	22,499,724	17,974,755	11,475,009	3,663,628	-	-	-	-	-	-	-
Total Cost of Off System Sales	68,196,801	58,435,281	48,032,148	37,451,312	29,326,667	18,487,937	5,841,457	-	-	-	-	-	-	-
Wholesale KG&E Revenue Requirement - $/MWH	46.11	47.56	49.02	50.36	52.09	53.39	54.62	55.76	56.81	57.76	58.61	59.36	60.11	60.88
Retail KG&E Revenue Requirement - $/MWH	718,683,467	754,252,253	793,142,651	831,693,447	877,938,749	925,180,675	976,236,913	1,032,854,469	1,094,740,944	1,159,977,447	1,228,581,228	1,300,566,747	1,376,900,139	1,458,046,645
Retail KG&E Revenue Requirement - $/MWH	69.54	71.15	72.93	74.55	76.72	78.81	81.07	83.61	86.39	89.24	92.13	95.08	98.13	101.29
KG&E - Average Rate ($/MWh)	69.54	71.15	72.93	74.55	76.72	78.81	81.07	83.61	86.39	89.24	92.13	95.08	98.13	101.29
Residential	90.86	92.96	95.29	97.41	100.24	102.98	105.92	109.25	112.88	116.60	120.39	124.23	128.21	132.35
Commercial	75.22	76.96	78.89	80.64	82.98	85.25	87.69	90.44	93.45	96.52	99.66	102.84	106.14	109.57
Industrial	49.29	50.43	51.69	52.84	54.38	55.86	57.46	59.26	61.23	63.25	65.30	67.39	69.55	71.80

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Street Light / Hwy	131.79	134.84	138.22	141.29	145.40	149.36	153.64	158.46	163.73	169.12	174.62	180.20	185.97	191.98
KG&E - Average Rate ($/MWh) - with 5% Franchise Fee	73.02	74.70	76.58	78.28	80.55	82.75	85.12	87.79	90.71	93.70	96.74	99.83	103.03	106.36
Residential	95.41	97.61	100.06	102.28	105.25	108.12	111.22	114.71	118.52	122.43	126.40	130.44	134.63	138.97
Commercial	78.98	80.80	82.83	84.67	87.13	89.51	92.07	94.96	98.12	101.35	104.64	107.99	111.45	115.05
Industrial	51.75	52.95	54.28	55.48	57.09	58.65	60.33	62.22	64.29	66.41	68.57	70.76	73.03	75.39
Street Light / Hwy	138.38	141.58	145.13	148.36	152.66	156.83	161.32	166.38	171.92	177.58	183.35	189.21	195.27	201.58